used in Vectren's baseload generators. The data response continues, "Its baseload coal units will remain the baseline of its supply resources for years to come." I have included the Company's full response to OUCC Data Request No. 9, Question 270 in my Exhibit__(RAG-2).

It would be economically irrational and in my opinion foolish for Vectren to plan its capacity mix by considering only its peak demands and ignoring all other customer requirements in its annual load duration curve. Moreover, Vectren's current capacity mix, and its expected reliance on baseload capacity for the foreseeable future are not consistent with a finding that the Company's peak demands are responsible for its total generation capacity related costs. Vectren would not have its baseload generation plants but for the existence of its customers' sustained electric demand requirements. In this important cost-causative sense, sustained demands bear cost responsibility for Vectren's electric generation plant.

Q. Is there other evidence that energy properly bears substantial generation fixed cost responsibility?

A. Yes, a primary regulatory standard is that regulation should attempt to achieve the same results that would be achieved if the regulated monopoly service were provided in the competitive sector of the economy. Vectren now operates in the Midwest Independent Transmission System Operator, an RTO that functions under Federal Energy Regulatory Commission regulation. Recent reported prices for the Northern Indiana ("NI") Hub for day-ahead February 12 delivery were 6.8¢ per kWh peak and 4.55¢ off-peak. Vectren's average FAC fuel cost of its electric generation is about 2.25¢ per kWh. Clearly, the electric power acquisition market reveals that energy prices determined in the marketplace include substantial fixed cost responsibility. The market reveals substantial fixed cost recovery associated with off-peak periods, and greater fixed cost recovery during peak periods. Vectren's pure peak allocation proposal, which exempts energy from any fixed generation cost responsibility, is inconsistent with revealed electric power procurement market results. A portion of fixed generation cost responsibility must be allocated on an energy basis if cost study results are to be consistent with electricity market-determined fixed cost recoveries.

Q. Is it reasonable to allocate Vectren's total generation plant and related costs only on the basis of four peak demands in the summer?

A. No. Vectren's $1.2 billion dollars invested in generation plant reflects the Company's current and expected baseload plant requirements as well as the Company's need for peaking plants. In my opinion, it would be incorrect to find that Vectren's total generation plant costs, including its higher-cost baseload plants, were caused by peak demands only. Peak demands are not solely responsible for investment costs related to Vectren's current generation plant mix. The more expensive baseload plant will be built when it can be operated for long periods of time so as to accumulate fuel and operating cost savings that overcome its higher capital costs compared to peaking plant. Thus, a portion of Vectren's generation plant costs relate to that generation plant being available to meet peak demands, and a portion of generation plant costs relate to the sustained energy demands that caused baseload plant, not peaking plant, to be included in (and dominate) the Company's generation plant mix.

Q. Proponents of various allocation schemes that rely on peak loads only argue that if you have enough plant to meet peak loads, then you automatically have enough capacity to meet all lesser demands, and so it is only peak demands and the need to service them that cause all generation plant costs. Is this correct?

A. No. If peak demands were the only demands that had to be met, and those demands would support the production of electricity with centralized generation plants, then only peaking plants would be required. Additional generation plant costs related to baseload plant are incurred when, in the planning process, consideration of the entire annual load duration curve reveals that there is enough sustained demand to warrant construction of a baseload plant. Thus, peak loads do not cause all generation plant related costs and it would be wrong to allocate Vectren's generation facilities, so overwhelmingly dominated by baseload plant, on peak demands only.

Q. Can you provide an example of how costs are misallocated when all generation plant and related costs are allocated on a peak demand basis only?

A. Yes. The 4-CP method utilized in the Vectren study allocates all generation plant cost, including the high-cost baseload plant, on the basis of each class's contribution to system peak demands. Rate (A) Residential Service customers are allocated 31 percent of total generation plant, including baseload plant, under this scheme. A prime benefit of baseload plant operations is the ability to use low-cost coal, which costs about 2.25¢ per kWh on Vectren's system. However, Rate (A) Residential customers receive only 21 percent of the low-cost energy benefit of baseload plant operations. This is so because fuel costs are allocated to class on the basis of annual energy usage. Thus, under Vectren's 4-CP allocation procedures, 31 percent of baseload plant costs are allocated to Rate (A) Residential customers' plant. Baseload facilities are included in the Company's generation plant mix largely because of the fuel cost savings associated with that plant. However, while responsible for 31 percent of all generation plant costs, Rate (A) Residential customers receive only 21 percent of the energy cost savings. Since the higher cost baseload plant costs are incurred, in part, based on sustained energy demands, and the energy-related benefits are allocated to customers based on their energy usages, it is incorrect to allocate the total baseload plant capital costs on the basis of customer loads only at the time of system peak demands.

Q. Is there an allocation method that recognizes the importance of both peak demands and sustained demands being responsible for Vectren's generation facilities costs?

A. Yes, the Peak and Average ("P&A") method of allocating costs does so partially on the basis of peak demands and partially on sustained demands. Measures of sustained demands include annual energy usages for each class, or average demands. Because class average demands are simply class total energy divided by the 8760 hours in a year, a constant number, class average demands bear the same relationship as class annual energy. The average demand portion of the Peak and Average method relates to sustained demands; the peak portion of the P&A method recognizes that peak demands also cause a portion of a utility's generation plant related costs.

Under the P&A cost allocation methodology, the proportion of plant allocated on average demands is based on the system load factor. Thus, if the utility's load factor were 0.52, then 52 percent of plant facilities would be allocated on average demands, while the remaining 48 percent of facilities would be allocated on peak demands. Similarly, if the load factor were 0.60, then 60 percent of generation plant would be allocated on average demands and 40 percent would be allocated on peak demands. The load factor percentage split explicitly recognizes the need to allocate a substantial portion of electric generating plant costs on average demands. As the load factor inherent in a utility's load duration curve increases, and baseload plant becomes more and more the plant of choice, the amount of plant allocated on average demands increases. Vectren's test year annual system load factor is 61 percent. Correspondingly, under the P&A method, 61 percent of the Company's generation plant would be allocated on average demands and 39 percent would be allocated on peak demands. This contrasts with Vectren's allocation of 100 percent of the Company's $1.2 billion total generation plant investment on peak demands only.

Q. Have you performed a class cost of service study that allocates Vectren's generating facilities and related costs on the basis of class peak and average demands?

A. Yes. The summary results of applying the P&A method to Vectren's generation plant facilities and related costs are reported in Exhibit__(RAG-3) page 1. Exhibit ____ (RAG-3), page 2 shows the indicated class rates of return on allocated rate base and index returns under both the Company's 4-CP, pure peak method, and the P&A method.

Q. Please summarize the difference between your class cost of service study, whose results are reported in Exhibit__(RAG-3) page 1, and the one performed by Vectren.

A. My class cost of service study utilizes the P&A method applied to generation plant and plant-related costs. The P&A study considers the impact that load duration has upon the inclusion of expensive baseload generation facilities in Vectren's portfolio of baseload and peaking plant. Vectren utilized the 4-CP method for the allocation of its fixed generation capacity costs. The 4-CP method assumes that all plant investment is driven by, or directly related to, peak demands only. In my opinion, the P&A method more closely matches cost causation than Vectren's 4-CP method.

B. <u>Allocation of Vectren's Primary, Secondary and Transformer Facilities and Related Costs</u>

Q. Please explain how Vectren allocated its primary and secondary distribution facilities and its transformers.

A. Primary distribution costs were allocated on equally weighted class factors consisting of the class demands at the times of the four system coincident peak demands, and the sum of each individual customer's maximum non-coincident peak demand whenever during the year each customer would reach its peak demand. Secondary distribution costs were allocated entirely on the basis of the sum of each customer's non-coincident peak demand summed for all the customers in each class. Transformers were allocated essentially 50 percent on the basis of each customer's individual non-coincident demand and the number of customers in each class.

Q. What is the rationale for including a customer component of costs in the classification of transformer facilities cost?

A. When discussing customer costs at page 6 of his testimony, Mr. Heid puts it this way:

> Customer-related costs are those that are associated with serving customers irrespective of either the amount of energy used or the maximum demand. For example, every customer has a meter and a service, and the carrying costs associated with these facilities, along with the cost of meter reading and billing have been classified as customer-related. These costs are allocable on factors that are related to the number of customers.

Vectren determined the amount of its transformer facilities cost that it classifies as a customer cost through its "zero intercept analysis." Under this method, a relationship is developed between costs per unit of transformation capacity and transformer size. The relationship is defined by the straight line that best fits the available data. Based on that fitted regression line, the cost of a zero-capacity transfer is estimated, and this estimated amount is declared to be the customer component of total transformer costs. Using this zero intercept analysis, Vectren determined the so-called customer component of transformers to be about one-half of its actual cost of transformers. The alleged logic of the zero intercept analysis is that Vectren would have incurred a $26.4 million cost to install transformers that would be incapable of providing any deliveries of transformed electricity. Vectren classified this $26.4 million as a customer cost and allocated this cost on the basis of the number of customers in each class. Vectren classified the remaining

$26.5 million of its actual transformer investment as demand related, and allocated this portion of costs on the sum of individual non-coincident peak demands.

Consistent with Mr. Heid's explanation included on page 14 of my direct testimony, this classification of essentially one-half of Vectren's total transformer investment cost as customer related requires that there be a fixed relationship between the number of customers and the number of transformers, e.g., each new customer would require one transformer, or each given number of new customers would require one transformer. However, there is not a unique relationship between the number of Vectren customers and the number of transformers.

Q. Please explain.

A. Vectren has 54,434 secondary transformers. When asked about the number of customers served by a single secondary transformer, Vectren explained that as few as one customer or as many as 20 or more customers could be served from a single transformer, depending on the transformer size and the proximity of customers. I have included Vectren's responses to OUCC Data Request No. 1, Questions 21 and 22 in my Exhibit__(RAG-4) attached to this testimony. Transformers are required when end-user loads are of sufficient duration so as to warrant the incurrence of costs, and transformers will be sized to meet the maximum coincident demand expected from the customers served from the transformer. Transformer facilities do not vary uniquely with the number of customers, but do relate to Vectren's end-user load characteristics. This stands in direct contradiction to Mr. Heid's customer classification standard included on page 14 of my testimony, that customer costs "... are those costs that are associated with serving customers irrespective of either the amount of energy used or the maximum demand."

Transformers are required to meet customer load requirements at all times, including the peak demand placed on each transformer. There is no unique requirement to install a transformer for each customer, or for any given number of customers. However, all electricity delivered to customers must be transformed to usable voltages, and additional transformer costs are incurred to meet the coincident peak demands placed on each transformer. The peak demands on each transformer are caused by the coincidence of customer demands, or the lack of diversity of demands, not by the number of customers. Thus, transformers are needed, and transformer costs are incurred, to meet demands for delivered electricity whenever those demands occur, and transformers must be sized to also meet the coincident peak demands of customers served from each transformer.

Q. You have explained that Vectren has classified none of its primary and secondary distribution plant and none of its transformer plant on the basis of energy. Is this reasonable?

A. No. Vectren has allocated its demand-classified primary and secondary distribution plant and transformers on its customers' single-hour peak demands, or in the case of its primary plant on the basis of an average of its customers' 4 hourly coincident peak demands and its customers' hourly maximum, non-coincident peak demands. Vectren totally excludes average demands from any cost responsibility for its distribution and transformer demand-classified costs.

From a practical point of view, if Vectren only had customers who wanted to be hooked up to an electric system and use electricity one hour or several hours per year, Vectren's distribution system, with its attendant costs, would be neither practical, nor would it even exist. From a financial perspective, if Vectren faced a market characterized by customers who wanted to be hooked up so they could use electricity only one-hour or several hours per year, Vectren would have difficulty raising capital for such an enterprise. In my opinion, Vectren's proposed allocation of distribution costs, which totally omits customers' energy, or average demands, from any cost responsibility, and is driven only by the existence of the number of customers and the peak demands during the one hour when the customer peaks or the several hours per year when the classes peak, does not result in costs being allocated on the basis of the services causing those costs to be incurred.

Q. What service demands have caused the costs related to Vectren's provision of distribution delivery service?

A. The demands for delivered electricity, both in annual amounts sufficient to warrant Vectren's existence and in amounts that reflect maximum demands, cause the costs that Vectren seeks to recover in this proceeding. These demands for electricity are what economists call "derived demands." Electricity is not demanded for its own sake; rather, electricity is demanded because people have a demand for things like heated and cooled living and working spaces, refrigerated and frozen and cooked foods, warm water showers, clean and dried clothes, home and business video and audio entertainment or presentations, or the desire to see clearly at night, and in general, the use of all the other electricity-using appliances and equipment that are used to satisfy the revealed demands of market participants. The use of all these electricity-using appliances creates the demands for delivered electricity on Vectren's system. These demands exist year-round, creating an annual demand for electric service. Without this annual demand in sufficient amounts there would be no Vectren delivery system costs of service because there would be no Vectren electric distribution system. It is the sustained demand for delivered electricity, which is ultimately responsible for Vectren's existence, and costs, which has been relieved of any cost responsibility by Vectren in its proposals to allocate its total primary and secondary distribution costs of providing service.

Now, if the annual demand for electricity delivered across Vectren's distribution system were an absolutely level amount each day of the year and each hour of the day, Vectren's distribution system would only have to be built to deliver this average hourly amount of capacity. A system designed to meet this constant average demand is the smallest sized system that could deliver the annual energy requirements of Vectren's customers. But electricity demands are not constant. At times, the demands for electricity delivery are higher than at other times. Vectren distribution operations exist not only to service its customers' average delivery service requirements, but Vectren must also stand ready to meet elevated electricity delivery service requirements whenever they exist throughout the year. From this perspective it is the annual, or average service demands, <u>and</u> the elevated, or peak, demands that cause Vectren to incur its costs of providing service. In my opinion, it is consistent with this practical, realistic view of Vectren's delivery service operations to conclude that Vectren's primary and secondary distribution costs are related partially to its customers' average demands for service and partially to its customers' peak demands for service, in contrast to Vectren's view that its costs are driven by the number of customers and their one or several hours per year peak demands only.

Q. Have you had prepared a study based on the view that Vectren's delivery costs are caused by customers' annual, or average, demands, and by customers having elevated demands that produce, at some time during the year, individual customer and class peak demands?

A. Yes. The peak and average cost study methodology explicitly recognizes that distribution plant upstream of services exists, and is caused in part by sustained electricity usage and in part by peak usage demands. Exhibit__(RAG-5) contains the summary page of a class cost of the service study that allocates Primary Distribution costs and Secondary Distribution costs (as well as generation plant and related costs) partially on the basis of class average demands and partially on the basis of class peak demands. Those study results are based on 61 percent weighting of average demands and a 39 percent weighting of peak demands. Theoretically, under the peak and average cost allocation methodology, the capacity required to deliver average demands is based on the ratio of average demands to peak demands, which is simply the definition of system load factor, because no smaller amount of system capacity could deliver the annual demands for electricity on the Vectren system. Vectren's system load factor is 61 percent. This means that if the Company's 5,627,602 MWh annual energy requirements were utilized at a steady flow throughout the year, its average demand each hour of the year would be 642 MW, or 61 percent of Vectren's peak demand allocator of 1,057 MW. Because Vectren's primary and secondary distribution plant must be sized to accommodate not only the Company's average demands, but also to deliver electricity at times of peak demand, the remaining 39 percent of primary and secondary distribution plant costs has been allocated on the same peak demand basis Vectren proposes.

Q. Please summarize the differences between your method and that proposed by Vectren.

A. My method recognizes that the cost of Vectren's primary, secondary and transformer facilities involves average demands as well as peak demands, while Vectren's allocations are based upon customer and class peak demands, or number of customers and customer peak demands. In my opinion, the allocation of this plant partially on average demands and partially on peak demands is far more consistent the principle of allocating costs on the basis of the service requirements that cause those costs.

III. Revenue Allocation

Q. Please explain how Vectren allocated is proposed rate increase.

A. Citing a previous SIGECO electric rate order, Vectren has proposed a 25 percent subsidy reduction in this proceeding. Consistent with the cited precedent, the subsidy that each class is either providing or receiving is reduced by 25 percent.

Q. How do you propose to allocate Vectren's proposed rate increase?

A. Accepting the 25 percent subsidy reduction guideline, my resulting proposed allocation of Vectren's requested increase is shown on Exhibit___(RAG-6), page 1. For the reader's convenience, I have included Vectren's proposed revenue increase spread on page 2 of Exhibit___(RAG-6). The differences in the two proposed revenue allocations result because Vectren based its revenue spread on the results of Mr. Heid's class cost of service study, whereas my proposed revenue spread is based on my class cost of service study results. Specifically, my proposed revenue spread is based on the cost study results reported in Exhibit__(RAG-3). The two proposed revenue spreads shown in Exhibit__(RAG-6) are based on Vectren's proposed $90.4 million electric revenue increase. While this should not be construed as an endorsement of Vectren's requested increase, it does provide the trier of fact with a convenient apples-to-apples revenue spread comparison.

Q. Why did you base your proposed revenue spread on the cost of service study results reported in Exhibit__(RAG-3), rather than on the study results reported in Exhibit__(RAG-5)?

A. The study results shown in Exhibit__(RAG-3) include the reallocation of costs limited to the power production function only. The study results shown in Exhibit__(RAG-5) also include changes in allocations at the distribution service level. The allocation of fixed costs associated with distribution facilities is controversial. The indicated rates of return for transmission level customers are unaffected by the cost reallocations at the distribution level. Study results for the major classes utilizing distribution facilities, including regular Rate (A) Residential Service customers, Home Heating customers, and Small and Demand General Service customers all show the same direction of movement of index returns under either of my studies compared to Vectren's study. Moreover, index return differentials for the major classes tend to be small under both of my studies. (This is so because of Vectren's relatively large investment in power production facilities.) I do not believe the Commission needs to consider and reach findings and conclusions regarding cost allocation issues at the distribution service level in order to reasonably allocate the rate increase in this proceeding.

Q. If the Commission authorizes a smaller rate increase than Vectren has requested, how should the smaller increase be allocated?

A. If the Commission authorizes a smaller rate increase than Vectren has proposed, the Company should be required to file compliance tariffs based on the same methodology reflected in Exhibit __(RAG-6), page 1.

IV. Rate Design

Q. Please explain Vectren's proposed regular Rate (A) Residential Service rate design.

A. Table 1 below shows Vectren's current and proposed monthly Rate (A) Residential Service electric rate design stated in its tariff.

Table 1

Vectren-Electric
Rate A Residential Service
Tariff Rate Design

	Current		Proposed	Proposed	Percent
	Units	Rate	Rate	Increase	Increase
Customer Facilities Charge	1	$4.35	$7.50	$3.15	72.4%
Energy Charge	First 250 kWh	8.235¢	14.001¢	5.766¢	70.0%
	Over 250 kWh	6.881¢	11.001¢	4.120¢	59.9%

While Vectren's proposed Rate (A) Residential Service ("Rate (A)") rate element increases are in the 60-72 percent range, the proposed Rate (A) rate increase is 22.3 percent. The reason for this apparent disparity between Vectren's proposed Rate (A) tariff rate increase and the proposed Rate (A) class increase is that Vectren is including in its proposed base rates a substantial amount of costs that is currently recovered through various per-kWh surcharges that total to 2.25¢ per kWh. Table 2 below shows the effective rate increases proposed by Vectren when the current per KWh rates are restated to include the current surcharges.

Table 2
Vectren-Electric
Rate (A) Residential Service
Actual Rate Design

	Current		Proposed	Proposed	Percent
	Units	Rate	Rate	Increase	Increase
Customer Facilities Charge	1	$4.35	$7.50	$3.15	72.4%
Energy Charge	First 250 kWh	10.489¢	14.001¢	3.512¢	33.5%
	Over 250 kWh	9.134¢	11.001¢	1.867¢	20.4%

A Rate (A) residential customer using more than 250 kWh currently pays a $4.35 customer charge, 10.489¢ per kWh for the first 250 kWh, and 9.134¢ per KWh for additional usage. The actual increase experienced by that customer at Vectren's proposed rates would be the proposed rates shown above, including the 72.4 percent proposed Customer Facilities' Charge increase, and the 33.8 percent and 20.4 percent proposed energy block price increases.

Q. **Do you agree with Vectren's proposed electric Rate (A) rate increase?**

A. No. There is an apparent balance to the nominal rate element increases revealed in the Table 1 rates shown above, except for the somewhat reduced tailblock rate increase. However, when the Vectren proposed rates are compared to current actual rates, as shown in Table 2 above, all semblance of balance and symmetry of rate element increases is revealed to be more apparent than real.

Vectren's fully allocated, average, embedded class cost of service study does not, and indeed is not, structured so as to reveal the cost of providing service by energy rate block. Consumption in the tailblock will occur later in the monthly billing cycle for every customer, but Vectren's cost study does not reveal costs by time of the month. Vectren's proposed 3.512¢ increase in its Rate (A) first block price is 88 percent greater than its proposed 1.867¢ tailblock rate increase. These disparate energy block proposed rate increases increase the tailblock discount from its current 1.355¢ per kWh percent to 3.000¢ per kWh, and combined with cycle billing, would result in many customers paying substantially different rates for the consumption of electricity that occurs on the very same day. By proposing a disproportionately large Customer Facilities' Charge increase, the result would be a rate design that is inconsistent with conservation activities. This is so because the greater the emphasis on monthly fixed Customer Charges, the lower are the rates that vary with the amount of usage, thus stimulating greater consumption.

Q. What Rate (A) Residential Service rate design do you propose?

A. I propose the rate design embodied in the rates shown in Table 3 below.

Table 3
Vectren-Electric
Rate (A) Residential Service
OUCC Rate Design

	Current		OUCC Proposed Rate	Proposed Increase	Percent Increase
	Units	Rate			
Customer Facilities Charge	1	$4.35	$5.50	$1.15	26.4%
Energy Charge	First 250 kWh	10.489¢	12.9706¢	2.4816¢	23.7%
	Over 250 kWh	9.134¢	11.6156¢	2.4816¢	27.2%

The OUCC Rate Design embodies about the same percentage increase in each rate element.[1] By increasing each energy block rate by the same 2.4816¢ per kWh, the current tailblock discount of 1.355¢ per kWh is maintained.

Q. Does this complete your testimony?

A. Yes.

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[1] The rate elements differ slightly due to rounding of the customer facilities charge and the proposal to increase both energy block rates by the identical absolute 2.4816¢ per kWh amount.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SOUTHERN INDIANA GAS AND	)	
ELECTRIC COMPANY D/B/A VECTREN	)	
ENERGY DELIVERY OF INDIANA, INC.	)	CAUSE NO. 43111
(VECTREN-ELECTRIC)	)	

EXHIBITS ACCOMPANYING DIRECT TESTIMONY

OF

RICHARD A. GALLIGAN

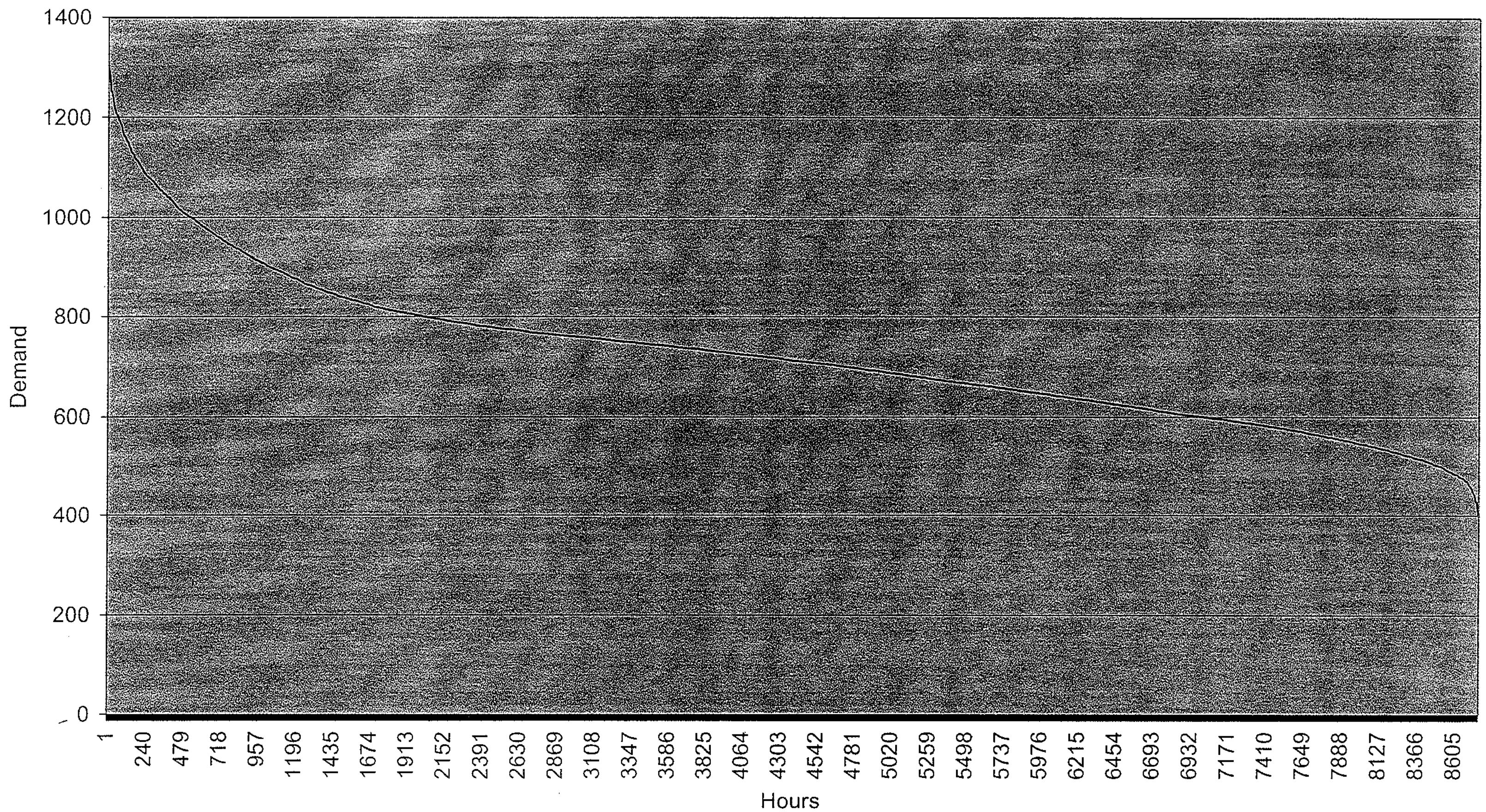
ON BEHALF OF INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

FEBRUARY 2007

EXETER
ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
LOAD DURATION CURVE

Exhibit__(RAG-1)



Q.270 See Benkert direct page 8, lines 18-26,

a) Does Vectren believe that implementing enhanced or additional energy efficiency programs will decrease Vectren's "credit challenges" in the eyes of financial rating agencies?]

b) What mechanisms has Vectren considered to quantify these decreases?

RESPONSE:

A) No. Over 95% of Vectren's energy is generated by coal. Vectren, with regulatory approval, has spent over $300 million in the last several years to comply with emissions standards. Its baseload coal units will remain the baseline of its supply resources for years to come. While reliance on a portfolio of supply side resources makes sense, and Vectren intends to build upon its Direct Load Control efforts by engaging once again in efficiency and other demand side efforts, Vectren will remain dependent on coal-fired generation.

B) Any marginal decrease in the % of supply provided by coal generation will not impact the credit rating agency perspective.

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
Production Cost Reallocation Only

Exhibit___(RAG-3)
Page 1 of 2

NORMALIZED COST OF SERVICE AT PRESENT RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:											
(1)	Revenue from Gas Sales	$324,589,615	$91,872,794	$29,154,071	$1,010,433	$5,982,248	$77,768,636	$6,164,062	$65,858,104	$43,803,418	$938,716	$2,037,132
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$13,826,505	$3,878,932	$90,198	$525,293	$11,980,615	$919,171	$8,680,791	$5,703,298	$41,721	$88,676
(4)	Total Operating Revenues	$412,659,810	$121,207,380	$36,409,958	$1,255,111	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
	OPERATING EXPENSES											
(5)	Production Demand	$36,627,104	$11,340,655	$2,708,265	$51,830	$286,427	$10,245,737	$753,815	$6,755,292	$4,485,082	$0	$0
(6)	Production Energy	$56,755,367	$11,897,860	$4,956,365	$157,304	$643,102	$13,093,197	$1,156,643	$14,141,276	$10,503,719	$72,656	$133,244
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$11,353,770	$2,807,588	$1,142,769	$27,951	$96,605	$3,000,490	$259,654	$2,337,955	$1,668,990	$5,186	$6,582
(9)	Sub-Transmission Demand	$12,591,218	$3,113,587	$1,267,319	$30,998	$107,134	$3,327,513	$287,954	$2,592,769	$1,850,893	$5,751	$7,299
(10)	Primary Distribution Demand	$1,754,745	$691,679	$312,061	$5,558	$10,474	$456,361	$44,169	$228,162	$0	$2,622	$3,659
(11)	Primary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(12)	Secondary Distribution Demand	$127,906	$60,692	$27,550	$379	$715	$34,562	$3,579	$0	$0	$179	$250
(13)	Secondary Distribution Customer	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14)	Line Transformers Demand	$1,835,672	$871,039	$395,389	$5,444	$10,261	$496,027	$51,360	$0	$0	$2,569	$3,584
(15)	Line Transformers Customer	$1,828,279	$1,105,041	$313,928	$65,622	$111,474	$98,679	$10,095	$1,231	$23	$104,028	$18,157
(16)	Services	$224,486	$127,441	$50,132	$0	$20,606	$23,865	$2,441	$0	$0	$0	$0
(17)	Meters	$2,270,291	$842,296	$313,699	$36,047	$225,468	$641,750	$65,653	$142,462	$2,916	$0	$0
(18)	Outdoor Lighting	$14,647	$0	$0	$0	$0	$0	$0	$0	$0	$14,647	$0
(19)	Street Lighting	$723,461	$0	$0	$0	$0	$0	$0	$0	$0	$0	$723,461
(20)	Customer Accounts-Related	$12,274,117	$7,626,674	$2,102,253	$304,729	$687,284	$879,739	$66,419	$109,525	$541	$399,536	$97,416
(21)	DSM-Related	$52,187	$16,158	$3,859	$74	$408	$14,598	$1,074	$9,625	$6,390	$0	$0
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma A Operating Costs	$301,768,572	$76,370,709	$27,639,288	$1,116,532	$3,993,519	$70,792,250	$6,034,821	$65,960,504	$47,726,681	$795,412	$1,338,857
(25)	Total Depreciation and Amortization Expense	$64,494,881	$18,303,336	$6,337,963	$177,422	$794,481	$15,953,062	$1,337,737	$12,583,384	$8,400,652	$215,102	$391,741
(26)	Other Taxes	(95,822)	(27,000)	(9,167)	(372)	(1,374)	(22,959)	(1,917)	(18,845)	(13,262)	(246)	(679)
(27)	Property Taxes	8,174,121	2,339,348	849,295	25,181	106,737	1,991,542	170,651	1,566,258	1,033,631	28,381	63,096
(28)	Utility Receipts Taxes	5,755,270	1,683,630	505,969	16,784	96,454	1,392,803	113,953	1,141,657	762,001	12,477	29,543
(29)	State Income Taxes	1,325,265	1,505,626	(64,691)	(11,297)	153,999	447,570	10,948	(247,343)	(474,197)	(10,160)	14,810
(30)	Federal Income Taxes	1,687,545	4,713,829	(554,921)	(52,409)	529,724	883,779	(25,621)	(1,578,993)	(2,216,479)	(46,990)	35,623
(31)	Total Operating Expenses	$383,109,832	$104,889,479	$34,703,737	$1,271,840	$5,673,539	$91,438,047	$7,640,573	$79,406,622	$55,219,027	$993,976	$1,872,991
(32)	Net Operating Income	$29,549,979	$16,317,901	$1,706,220	($16,729)	$1,311,636	$8,132,766	$507,600	$2,141,546	($790,240)	($13,540)	$252,817
(33)	Total Rate Base	$1,017,759,890	$291,433,112	$105,402,230	$3,101,374	$12,542,079	$250,396,368	$21,409,596	$195,555,624	$128,072,733	$2,745,882	$7,100,894
(34)	Rate of Return	2.90%	5.60%	1.62%	-0.54%	10.46%	3.25%	2.37%	1.10%	-0.62%	-0.49%	3.56%
(35)	Index	1.00	1.93	0.56	(0.19)	3.60	1.12	0.82	0.38	(0.21)	(0.17)	1.23

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
PRODUCTION COST REALLOCATION ONLY

		Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)	Total
P&A Study	Rate of Return	5.60%	1.62%	-0.54%	10.46%	3.25%	2.37%	1.10%	-0.62%	-0.49%	3.56%	2.90%
	Index	1.93	0.56	-0.19	3.61	1.12	0.82	0.38	-0.21	-0.17	1.23	1.00
4-CP Study	Rate of Return	3.49%	2.34%	1.87%	13.28%	2.15%	2.32%	3.08%	2.13%	2.12%	5.92%	2.90%
	Index	1.20	0.81	0.64	4.58	0.74	0.80	1.06	0.73	0.73	2.04	1.00

21. Please provide breakdowns of the number of transformers, and the amount of related facilities cost, by primary and secondary classification.

Response: The property records in Account 368-Line Transformers do not differentiate between primary and secondary voltages. However, as a general rule, line transformers transform voltage from primary voltage levels to the secondary voltage levels and would therefore be consider secondary transformers. Account 368 reflects a total of 54,434 transformers.

22. For secondary transformers, please provide the smallest number of customers served by a single transformer, and the largest number of customers served by a single transformer.

Response: Secondary transformers can serve as few as one customer and as many as twenty or more customers, depending upon the transformer size and proximity of customers.

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
Production and Distribution Reallocation

Exhibit___(RAG-5)

NORMALIZED COST OF SERVICE AT PRESENT RATES

		TOTAL	Residential (A)	Electric Home Heating (EH)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Off-Season Service (OSS)	Large Power Service (LP)	Transmission Power (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	OPERATING REVENUES:											
(1)	Revenue from Gas Sales	$324,589,615	$91,872,794	$29,154,071	$1,010,433	$5,982,248	$77,768,636	$6,164,062	$65,858,104	$43,803,418	$938,716	$2,037,132
(2)	Revenues from Riders	$42,334,996	$15,508,081	$3,376,955	$154,480	$477,634	$9,821,563	$1,064,940	$7,009,273	$4,922,070	$0	$0
(3)	Miscellaneous Revenues	$45,735,200	$13,826,505	$3,878,932	$90,198	$525,293	$11,980,615	$919,171	$8,680,791	$5,703,298	$41,721	$88,676
(4)	Total Operating Revenues	$412,659,810	$121,207,380	$36,409,958	$1,255,111	$6,985,175	$99,570,813	$8,148,173	$81,548,168	$54,428,787	$980,437	$2,125,808
	OPERATING EXPENSES											
(5)	Production Peak Demand	$38,625,222	$11,340,072	$2,708,126	$51,827	$286,412	$10,245,211	$753,777	$6,754,945	$4,484,852	$0	$0
(6)	Production Average Demand	$56,757,249	$11,898,254	$4,956,530	$157,309	$643,123	$13,093,631	$1,156,681	$14,141,745	$10,504,067	$72,659	$133,249
(7)	FAC Fuel	$127,995,233	$26,832,164	$11,177,641	$354,753	$1,450,330	$29,527,900	$2,608,472	$31,891,538	$23,688,085	$163,856	$300,494
(8)	Transmission Demand	$11,353,770	$2,807,588	$1,142,769	$27,951	$96,605	$3,000,490	$259,654	$2,337,955	$1,668,990	$5,186	$6,582
(9)	Sub-Transmission Demand	$12,591,218	$3,113,587	$1,267,319	$30,998	$107,134	$3,327,513	$287,954	$2,592,769	$1,850,893	$5,751	$7,299
(10)	Primary Distribution Peak Demand	$697,144	$274,798	$123,979	$2,208	$4,161	$181,308	$17,548	$90,647	$0	$1,042	$1,453
(11)	Primary Distribution Average Demand	$1,057,601	$416,881	$188,082	$3,350	$6,313	$275,053	$26,621	$137,515	$0	$1,581	$2,205
(12)	Secondary Distribution NCP Demand	$50,162	$23,802	$10,804	$149	$280	$13,555	$1,403	$0	$0	$70	$98
(13)	Secondary Distribution Average Demand	$77,744	$36,890	$16,745	$231	$435	$21,008	$2,175	$0	$0	$109	$152
(14)	Line Transformers NCP Demand	$1,835,672	$871,039	$395,389	$5,444	$10,261	$496,027	$51,360	$0	$0	$2,569	$3,584
(15)	Line Transformers Average Demand	$1,828,279	$867,531	$393,796	$5,422	$10,219	$494,029	$51,153	$0	$0	$2,559	$3,569
(16)	Services	$224,486	$127,441	$50,132	$0	$20,606	$23,865	$2,441	$0	$0	$0	$0
(17)	Meters	$2,270,291	$842,296	$313,699	$36,047	$225,468	$641,750	$65,653	$142,462	$2,916	$0	$0
(18)	Outdoor Lighting	$14,647	$0	$0	$0	$0	$0	$0	$0	$0	$14,647	$0
(19)	Street Lighting	$723,461	$0	$0	$0	$0	$0	$0	$0	$0	$0	$723,461
(20)	Customer Accounts-Related	$12,274,117	$7,626,674	$2,102,253	$304,729	$687,284	$879,739	$66,419	$109,525	$541	$399,536	$97,416
(21)	DSM-Related	$52,187	$16,158	$3,859	$74	$408	$14,598	$1,074	$9,625	$6,390	$0	$0
(22)	Non-FAC Fuel	$19,045,083	$3,992,499	$1,663,180	$52,786	$215,802	$4,393,611	$388,128	$4,745,310	$3,524,675	$24,381	$44,712
(23)	WPM Fuel	$16,295,008	$5,045,336	$1,204,878	$23,059	$127,428	$4,558,219	$335,364	$3,005,357	$1,995,365	$0	$0
(24)	Total Proforma A Operating Costs	$301,768,572	$76,133,011	$27,719,181	$1,056,335	$3,892,271	$71,187,508	$6,075,879	$65,959,394	$47,726,775	$693,944	$1,324,274
(25)	Total Depreciation and Amortization Expense	$64,494,881	$18,189,671	$6,361,371	$153,266	$753,827	$16,139,200	$1,353,029	$12,583,442	$8,400,708	$174,526	$385,841
(26)	Other Taxes	(95,822)	(26,830)	(9,224)	(329)	(1,301)	(23,242)	(1,947)	(18,844)	(13,262)	(174)	(668)
(27)	Property Taxes	8,174,121	2,317,964	853,699	20,635	99,087	2,026,572	173,529	1,566,266	1,033,638	20,745	61,985
(28)	Utility Receipts Taxes	5,755,270	1,683,630	505,969	16,784	96,454	1,392,803	113,953	1,141,657	762,001	12,477	29,543
(29)	State Income Taxes	1,325,265	1,542,080	(74,826)	(2,727)	168,416	387,360	5,272	(247,256)	(474,212)	4,265	16,893
(30)	Federal Income Taxes	1,687,545	4,854,526	(593,798)	(19,408)	585,243	651,437	(47,456)	(1,578,666)	(2,216,536)	8,556	43,646
(31)	Total Operating Expenses	$383,109,832	$104,694,052	$34,762,372	$1,224,555	$5,593,997	$91,761,638	$7,672,260	$79,405,993	$55,219,112	$914,340	$1,861,513
(32)	Net Operating Income	$29,549,979	$16,513,328	$1,647,586	$30,556	$1,391,178	$7,809,175	$475,913	$2,142,176	($790,325)	$66,097	$264,295
(33)	Total Rate Base	$1,017,759,890	$288,912,402	$105,921,369	$2,565,514	$11,640,262	$254,525,695	$21,748,817	$195,556,481	$128,073,562	$1,845,796	$6,969,993
(34)	Rate of Return	2.90%	5.72%	1.56%	1.19%	11.95%	3.07%	2.19%	1.10%	-0.62%	3.58%	3.79%
(35)	Index	1.00	1.97	0.54	0.41	4.12	1.06	0.75	0.38	(0.21)	1.23	1.31

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
COMPARISON OF PROFORMA OPERATING REVENUES AND DOLLAR SUBSIDY LEVELS

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		PROFORMA REVENUES - PRESENT RATES			PROFORMA REVENUES - PROPOSED RATES				
		Revenues At Present Rates	Revenues Required For Equalized	Present Subsidy	Revenues Required For Equalized	Revenues At Proposed Rates	Proposed Subsidy	Subsidy Reduction	
Line	Rate Schedule							Amount	Percentage
(1)	Residential (A)	$121,207,380	$107,792,564	$13,414,816	$133,373,267	$143,434,380	$10,061,113	$3,353,703	25.00%
(2)	Electric Home Heating (EH)	$36,409,958	$38,722,014	($2,312,056)	$47,996,492	$46,262,449	($1,734,043)	($578,013)	25.00%
(3)	Water Heating (B)	$1,255,111	$1,437,431	($182,320)	$1,670,512	$1,533,772	($136,740)	($45,580)	25.00%
(4)	Small General Service (SGS)	$6,985,175	$5,367,341	$1,617,834	$6,419,399	$7,632,774	$1,213,375	$404,459	25.00%
(5)	Demand General Service (DGS)	$99,570,813	$98,097,810	$1,473,003	$120,559,669	$121,664,421	$1,104,752	$368,251	25.00%
(6)	Off-Season Service (OSS)	$8,148,173	$8,342,855	($194,682)	$10,257,194	$10,111,182	($146,012)	($48,670)	25.00%
(7)	Large Power Service (LP)	$81,548,168	$87,586,422	($6,038,254)	$105,166,559	$100,637,869	($4,528,690)	($1,509,564)	25.00%
(8)	Transmission Power (HLF)	$54,428,787	$62,127,527	($7,698,740)	$73,644,596	$67,870,541	($5,774,055)	($1,924,685)	25.00%
(9)	Outdoor Lighting (OL)	$980,437	$1,139,687	($159,250)	$1,310,247	$1,190,810	($119,437)	($39,813)	25.00%
(10)	Street Lighting (SL)	$2,125,808	$2,046,158	$79,650	$2,671,675	$2,731,413	$59,738	$19,912	25.00%
(11)	Total	$412,659,810	$412,659,809	$1	$503,069,610	$503,069,611	$1	$0	

VECTREN ENERGY DELIVERY OF INDIANA - ELECTRIC
IURC CAUSE NO. 43111
COST OF SERVICE STUDY
COMPARISON OF PROFORMA OPERATING REVENUES AND DOLLAR SUBSIDY LEVELS

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF

PETITIONER'S EXHIBIT KAH-4
SCHEDULE 1

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		PROFORMA REVENUES - PRESENT RATES			PROFORMA REVENUES - PROPOSED RATES				
Line	Rate Schedule	Revenues At Present Rates	Revenues Required For Equalized Returns	Present Subsidy	Revenues Required For Equalized Returns	Revenues At Proposed Rates	Proposed Subsidy	Subsidy Reduction Amount	Subsidy Reduction Percentage
(1)	Residential (A)	$121,207,380	$117,904,239	$3,303,141	$147,073,700	$149,551,055	$2,477,356	$825,785	25.00%
(2)	Electric Home Heating (EH)	$36,409,958	$37,368,236	($958,278)	$46,162,241	$45,443,532	($718,709)	($239,570)	25.00%
(3)	Water Heating (B)	$1,255,111	$1,300,249	($45,138)	$1,484,643	$1,450,789	($33,853)	($11,284)	25.00%
(4)	Small General Service (SGS)	$6,985,175	$5,012,282	$1,972,894	$5,938,324	$7,417,995	$1,479,670	$493,223	25.00%
(5)	Demand General Service (DGS)	$99,570,813	$103,056,609	($3,485,796)	$127,278,407	$124,664,059	($2,614,347)	($871,449)	25.00%
(6)	Off-Season Service (OSS)	$8,148,173	$8,363,219	($215,046)	$10,284,784	$10,123,500	($161,284)	($53,761)	25.00%
(7)	Large Power Service (LP)	$81,548,168	$81,040,752	$507,416	$96,297,751	$96,678,313	$380,562	$126,854	25.00%
(8)	Transmission Power (HLF)	$54,428,787	$55,795,250	($1,366,464)	$65,064,918	$64,040,070	($1,024,848)	($341,616)	25.00%
(9)	Outdoor Lighting (OL)	$980,437	$1,010,228	($29,791)	$1,134,842	$1,112,499	($22,343)	($7,448)	25.00%
(10)	Street Lighting (SL)	$2,125,808	$1,808,745	$317,063	$2,350,001	$2,587,798	$237,797	$79,266	25.00%
(11)	Total	$412,659,810	$412,659,809	$1	$503,069,610	$503,069,611	$1	$0	

PUBLIC'S EXHIBIT NO. 6

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA	)	
GAS AND ELECTRIC COMPANY d/b/a	)	
VECTREN ENERGY DELIVERY OF	)	
INDIANA, INC. (VECTREN) FOR	)	CAUSE NO. 43111
AUTHORITY TO INCREASE ITS	)	
RATES AND CHARGES FOR	)	
ELECTRIC UTILITY SERVICES	)	

DIRECT TESTIMONY

OF

THOMAS S. CATLIN

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

FEBRUARY 27, 2007

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

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BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICES	)	CAUSE NO. 43111

Direct Testimony of Thomas S. Catlin

Qualifications

Q. Would you please state your name and business address?

A. My name is Thomas S. Catlin. I am a principal with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Suite 310, Columbia, MD 21044. Exeter is a firm of consulting economists specializing in issues pertaining to public utilities.

Q. Please describe your educational background.

A. I hold a Master of Science Degree in Water Resources Engineering and Management from Arizona State University (1976). Major areas of study for this degree included pricing policy, economics, and management. I received my Bachelor of Science Degree in Physics and Math from the State University of New York at Stony Brook in 1974. I have also completed graduate courses in financial and management accounting.

Q. Would you please describe your professional experience?

A. From August 1976 until June 1977, I was employed by Arthur Beard Engineers in Phoenix, Arizona, where, among other responsibilities, I conducted economic feasibility, financial and implementation analyses in conjunction with utility construction projects. I also served as project engineer for two utility valuation studies.

From June 1977 until September 1981, I was employed by Camp Dresser & McKee, Inc. (CDM). Prior to transferring to the Management Consulting Division of CDM in April 1978, I was involved in both project administration and design. My project administration responsibilities included budget preparation as well as labor and cost monitoring and forecasting. As a member of CDM's Management Consulting Division, I performed cost of service, rate, and financial studies involving approximately 15 municipal and private water, wastewater and storm drainage utilities. These projects included: determining total costs of service; developing capital asset and depreciation bases; preparing cost allocation studies; evaluating alternative rate structures and designing rates; preparing bill analyses; developing cost and revenue projections; and preparing rate filings and expert testimony.

In September 1981, I accepted a position as a utility rates analyst with Exeter Associates, Inc. I became a principal and vice-president of the firm in 1984. Since joining Exeter, I have continued to be involved in the analysis of the operations of public utilities, with particular emphasis on utility rate regulation. I have been extensively involved in the review and analysis of utility rate filings, as well as other types of proceedings before state and federal regulatory authorities. My work in utility rate filings has focused on revenue requirements issues, but has also addressed service cost and rate design matters. I have also been involved in analyzing affiliate relations, alternative regulatory mechanisms, and regulatory restructuring issues. This experience has involved electric, telephone, water and wastewater utilities, as well natural gas transmission and distribution companies.

Q. Have you previously testified in regulatory proceedings on utility rates?

A. Yes. I have previously presented testimony on more than 200 occasions before the Federal Energy Regulatory Commission and the public utility commissions of Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Idaho, Illinois, Kentucky, Louisiana, Maine, Maryland, Montana, Nevada, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Utah, Virginia and West Virginia, as well as before this Commission. I have also filed rate case evidence by affidavit with the Connecticut Department of Public Utility Control and have appeared as an expert witness on behalf of the Louisiana Public Service Commission before the Nineteenth Judicial District Court.

Q. On whose behalf are you appearing?

A. I am presenting testimony on behalf of the Indiana Office of Utility Consumer Counselor (OUCC).

Purpose and Conclusion

Q. What is the purpose of your testimony?

A. Exeter Associates has been asked by the OUCC to review the reasonableness of the level of revenues that Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. – Electric Division (Vectren or the Company) is proposing to charge its customers. My assignment in this proceeding was to examine and investigate the Company's revenue requirement, and to present my findings regarding Vectren's test year rate base and net operating income at present rates. In developing my recommendations with regard to net operating income, I have incorporated the recommendations of Ms. Joan Soller regarding certain adjustments to incremental maintenance program costs and of Dr. Michael J. Ileo regarding depreciation expense.

Based on my findings, I have determined the revenues that are required to generate the overall rate of return on rate base recommended by Dr. J. Randall Woolridge on behalf of the OUCC.

Q. Have you prepared schedules to accompany your testimony?

A. Yes, I have. Schedules TSC-1 through TSC-32 are attached to my testimony. These schedules present my findings and recommendations regarding the Company's test year revenue requirements.

Q. Please summarize your findings regarding the Company's revenue requirement.

A. As shown on Schedule TSC-1, I have determined the Company has a revenue deficiency of $51,414,445 for the test year ended March 31, 2006. This amount represents a reduction of $38,995,356 compared to the increase of $90,409,801 requested by Vectren. This increase in revenues will generate an overall rate of return of 6.77 percent after accounting for the OUCC's adjustments to Vectren's claimed rate base and operating income. The return of 6.77 percent represents Dr. Woolridge's finding regarding the Company's overall fair rate of return on rate base.

Schedule TSC-2 summarizes my adjustments to Vectren's proposed test year rate base. Schedule TSC-3 provides a summary of my adjustments to test year revenues and expenses and the resulting net income at present rates. Schedule TSC-4 provides a proof of income taxes at present and proposed rates. Schedules TSC-5 through TSC-30 presents each of the adjustments that I have made to rate base and net operating income. Schedule TSC-31 presents a comparison of the Company's and the OUCC's adjustments to net operating income per books. Schedule TSC-32 provides a comparison of Vectren's and the OUCC's calculation of required revenue increase.

Q. How is the remainder of your testimony organized?

A. In the remainder of my testimony, I document and explain each of the adjustments to rate base and operating income that I have made to arrive at the test year revenue deficiency shown on Schedule TSC-1. My discussion of these adjustments is organized into sections corresponding to the issue being addressed. These sections are set forth in the Table of Contents for this testimony.

<u>Rate Base</u>

Q. Please explain the changes you have recognized with regard to rate base?

A. In its filing, Vectren utilized a rate base that reflected investments as of March 31, 2006 adjusted to reflect estimated additions to transmission plant and the fabric filter at Culley Unit 3. Subsequently, the Company provided an update to reflect actual investment as of October 31, 2006 plus the projected investment in the Culley Unit 3 fabric filter. According to the Prehearing Conference Order Vectren was permitted to update its plant as of the time of the hearing on its case-in-chief pursuant to 170 IAC 1-5-5(3)(B) and to include the projected investment in the Culley Unit 3 fabric filter as a major plant addition pursuant to 170 IAC 1-5-5(4) subject to review as to its cost and status at the hearing on April 12, 2007. Therefore, I have recognized the Company's updated rate base claim in developing the OUCC's recommendation in this proceeding. Consistent with the Prehearing Conference Order, the OUCC reserves the right to review the evidence on the status and cost of the Culley Unit 3 Fabric Filter to be presented prior to the April 12, 2007 hearing. As shown on Schedule TSC-5, recognizing Vectren's updated claim increases rate base by $24,439,083 compared to the Company's initial filing.

Fuel Handling Expense

Q. Please explain your adjustment to fuel handling expense.

A. In its filing, Vectren adjusted fuel handling expense from the test year level of $4.30 million to a pro forma level of $4.63 million. According to the response to OUCC data request Q-83 (OUCC-83), the Company's claimed pro forma expense reflects its budgeted fuel handling expense for 2006. In response to OUCC-84, however, Vectren indicated that actual fuel handling expense for the 12 months ended October 2006 (the most recent data at the time of the response) was only $4.16 million. Accordingly, the claimed increase in fuel handling expense has not materialized and instead fuel handling expense has been below test year levels. Therefore, I have adjusted fuel handling expense to exclude the pro forma increase and to reflect the actual test year expense. As shown on Schedule TSC-6, this adjustment reduces test year expense by $332,391.

Restricted Stock and Stock Options Expense

Q. What adjustment have you made to the restricted stock and stock options expense that Vectren has included in its filing?

A. The Company projected that restricted stock and stock options expense would increase from a test year level of $712,455 to a pro forma level of $1,329,745. This pro forma level of expense is based on projected 2006 costs with adjustments to add back forfeitures for 2005 and 2006 to further adjust costs to a targeted level. This pro forma claim represents a significant increase over 2003, 2004 and 2005 restricted stock and stock options expense, as well as over the test year expense. In response to OUCC-173, the Company provided the actual amounts for restricted stock and stock options costs through September 2006 and the estimated expense for 2006. The projected 2006 expense of $861,241 is in line with the expense recorded in the test year and in 2003 - 2005. Therefore, I have adjusted the restricted stock and stock options expense to reflect the projected expense for 2006. As shown on Schedule TSC-7, this adjustment reduces test year expense by $468,504.

Vectren Incentive Plan Expense

Q. Please explain your adjustment to Vectren's incentive plan expense.

A. During the test year, Vectren incurred incentive plan expense of $2.24 million. The Company has proposed to increase this to a pro forma level of $2.55 million based on budgeted expense for 2006 times two. According to the response to OUCC-34, the 2006 budgeted expense was doubled because the budget was based on meeting 50 percent of the target and the pro forma expense was set equal to 100 percent of the target. In response to OUCC-174, Vectren indicated that it now estimates 2006 incentive plan expense to be $1.74 million, less than 75 percent of the target. Consistent with my adjustment to restricted stock expense, I have adjusted incentive plan expense to reflect Vectren's estimate of actual 2006 expense. As shown on Schedule TSC-8, this adjustment reduces Vectren's claimed test year expense by $804,062.

Headcount Adjustment

Q. How did Vectren develop its claimed level of labor costs?

A. In its filing, Vectren first annualized labor costs to reflect employee levels, wage rates, and fringe benefit and payroll tax adders as of the end of the test year on March 31, 2006 (Exhibit MSH-3, Adjustment A15). The Company then further adjusted labor expense to reflect additional employees projected to be added through March 31, 2005 (Adjustment

A21). Finally, as part of its other adjustments for aging workforce and certain new maintenance programs, the Company recognized other employee additions expected to take place, primarily subsequent to March 31, 2007.

Q. What adjustment are you proposing to make to Vectren's claimed labor costs?

A. As discussed subsequently, Ms. Soller and I will separately address the Company's aging workforce and new maintenance programs and the labor cost for new employees included in those programs. With regard to the headcount additions that Vectren included for the 12 months ending March 31, 2007, I am proposing to adjust the Company's claim to only include actual employee additions. This is necessary to limit labor costs to their fixed, known and measurable level.

Q. Are there any potential employee reductions that would offset additional headcount additions?

A. Yes. As recognized in Exhibit MSH-3, Adjustment A28, Vectren's Culley Unit 1 is being shutdown. In this adjustment, the Company only recognized reductions in material costs and overtime labor. No reduction in non-overtime labor was recognized for the elimination of the twelve employees at Culley Unit 1 nor were those employees assumed to be transferred to fill other positions.

According to the response to OUCC-99, two of the twelve positions at Culley Unit 1 have become vacant since the time of the filing. It is also my understanding that efforts are ongoing to either transfer the remaining ten employees to fill other positions or to eliminate the remaining ten positions. In developing my recommendation on behalf of the OUCC, I have not taken any of these savings into consideration. Instead, I have assumed that reductions in or transfer of Culley Unit One employees would offset the cost of other headcount additions.

Q. What is the effect of your adjustment on Vectren's claimed pro forma cost of service?

A. As shown on Schedule TSC-9, the labor costs associated with actual employee additions as provided in response to OUCC-37 is $182,679 compared to the Company's claimed increase of $1,671,867, this represents a reduction in test year expense of $1,489,197. In calculating the labor costs for the new employees, I have reflected a labor loading factor of 58.5 percent rather than the 59 percent factor utilized by Vectren. This change is discussed in the following section of my testimony.

I would note that the employee additions that I have recognized were those that had taken place as of approximately October 31, 2006. Subject to the opportunity to review and discovery, it would be reasonable to update to reflect fixed, known and measurable employee additions and reductions through the end of March 2007.

Payroll Taxes

Q. Please explain what adjustment you have made to payroll taxes.

A. In each of its adjustments to payroll and labor expense, Vectren has included a fringe benefit and payroll tax loading factor of 59 percent. The payroll tax factor of 8.0 percent included in this overall rate includes a loading of 7.50 percent for payroll taxes on salaries and wages plus an additional 0.50 percent intended to account for the payroll taxes on incentive compensation. Because this 0.50 percent increment is based on budgeted incentive compensation and budgeted overall salaries and wages, upward adjustments to labor expense will tend to cause payroll taxes to be overstated. Similarly, because incentive compensation was above budget in 2006, use of this 0.5 percent adder applied to salaries and wages will tend to cause payroll taxes to be understated. Therefore, I have adjusted the payroll tax factor to exclude the 0.50 percent adder for incentive compensation and have separately accounted for the payroll taxes on that compensation.

Schedule TSC-10 presents my adjustment to exclude the 0.50 percent adder from annualized labor expense and to directly recognize the payroll taxes on Vectren Incentive Plan expense. On this schedule, I have only removed the 0.50 percent adder from the annualized labor for existing employees and from the Company's adjustments for Customer Contact Center and Asset Management Program labor increases. I have separately accounted for the effect of changing the FICA adder on other labor costs as part of my adjustments to specific components of the Company's claims for additional labor costs (e.g., increases in headcount, aging workforce, etc.)

Aging Workforce Costs

Q. Please briefly summarize Vectren's request related to aging workforce costs.

A. Vectren is faced with the situation where many of its employees are beginning to reach retirement age. In this proceeding, the Company has requested that it be allowed to include in its cost of service the costs of hiring and training new apprentices to take the place of employees expected to retire over the next 3 to 4 years in both its power supply and energy delivery operations. In the power supply area, Vectren has included the cost of 14 new apprentices plus 8 additional employees for a training program. In the energy delivery area, Vectren has requested inclusion of 15 electric apprentices and co-ops plus 4 new supervisory and training positions. In addition, as part of its aging workforce adjustment for energy delivery operations, the Company has included the costs for 4 new human resources (HR) personnel and various other HR costs.

Q. What is your recommendation with regard to the recognition of aging workforce costs?

A. Although the costs that Vectren is seeking to recover will largely if not entirely begin to be incurred after March 31, 2007, the OUCC recognizes that addressing the Company's aging workforce is important. Accordingly, I am recommending that the costs associated with these programs be recognized for ratemaking, subject to several adjustments.

Q. What adjustments are you recommending with regard to Vectren's claim for aging workforce costs related to power supply operations?

A. First, I am proposing to adjust Vectren's claimed costs to recognize the savings associated with the retirement of existing power supply employees that will occur during the same time period that the new apprentices will be hired. According to the response to OUCC-249, two power supply electricians and two repair mechanics are expected to retire in 2006 and 2007. Recognizing these retirements is appropriate in order to reflect the net increase in costs that Vectren will experience from replacing its power supply workforce in 2007. I would note that the Company recognized the savings from similar 2006 and 2007 retirements in developing its claim for aging workforce costs for its energy delivery operations.

Q. What is the effect of recognizing retirements on Vectren's requested level of power supply aging workforce costs?

A. As shown on page 2 of Schedule TSC-11, recognizing the retirement of two power supply electricians and two repair mechanics results in labor cost savings of $352,766 that were not recognized by Vectren.

Q. What is the second adjustment that you are proposing to make to the costs associated with the aging workforce program for power supply operations?

A. The second adjustment that I am proposing to make to the Company's claim is to exclude the costs associated with certain new employees that have been included under the power supply training program. As part of its training costs, Vectren has included two new part-time subject matter experts for each of its two generating stations (one for operations and one for electrical/mechanical systems). During informal discussions, Vectren indicated that it was proposing separate subject matter experts for each plant because the plants have different systems. However, it is also my understanding that the two plants are less than 60 miles apart. Therefore, to reduce costs, I am proposing to include the costs for two full-time subject matter experts to be shared between the two facilities instead of four part-time employees (at approximately 2/3rds time). I am also proposing to exclude the costs that the Company has included in its training program for three new clerical employees. While the OUCC recognizes the importance of a training program for the new power supply apprentices, Vectren has not demonstrated the need for three new clerical workers as part of this program.

Q. How do the two changes that you have proposed affect the total power supply training program costs?

A. As shown on the lower portion of page 2 of Schedule TSC-11, I am proposing to recognize power supply training costs of $290,885. Compared to Vectren's proposal to include $493,000 of such costs, my proposal represents a reduction of $202,115. Most of this difference is due to the exclusion of nearly $142,000 for the three clerical workers. The remainder is due to scaling back the amount of time included for subject matter experts. I have accepted Vectren's claim for one new CAD technician as well as its request for "Critical Thinking" training costs.

Q. Have you prepared a schedule that summarizes your recommendation with regard to power supply aging workforce costs?

A. Yes. Page 1 of Schedule TSC-11 summarizes my recommendation on behalf of the OUCC. As shown there, my adjustments to reflect retirements and to reduce training program costs, along with the change in the payroll loading factor discussed previously, result in a reduction in power supply aging workforce program costs of $557,569.

Q. What adjustments are you proposing to make to the costs that Vectren has requested for its energy delivery aging workforce program?

A. I have made three adjustments to the costs that Vectren has included for its energy delivery aging workforce program in addition to the change discussed previously with regard to the payroll tax loader. First, Vectren has included a total of $166,500 for electrical apprenticeship training ($135,000) and development ($30,000). One element of these costs is $25,000 of internal labor associated with existing personnel. I have adjusted the apprenticeship training and developmental costs to exclude this $25,000 of internal labor. Vectren has separately accounted for the full annualized labor costs associated with all existing personnel (Exhibit MSH-3, Adjustment A15) and with anticipated additions through March 31, 2007 (Exhibit MSH-3, Adjustment A21). Therefore, the Company has already recognized all internal labor for existing employees and it would be improper to include an additional $25,000 as part of the electrical apprenticeship training program.

Second, the Company has included the hiring of eight line specialist apprentices to cover upcoming retirements plus an additional three line specialist apprentices to allow for a 25 percent attrition factor among the new line specialist apprentices. I am proposing to include the cost for the eight line specialists to replace upcoming retirees, but have adjusted the company's claim to exclude the three additional line specialists proposed to cover attrition. Given that all of the new employees to be hired under the aging workforce programs will not be hired until later in 2007 or into 2008 (per the response to

OUCC-97), it is unduly speculative to also include additional employees to cover attrition among the employees being hired to fill a specific need.

Finally, I have adjusted the Company's claim to exclude the $423,977 of human resources (HR) costs that the Company has requested as part of its aging workforce claim. The HR functions and activities included as part of the request are already being performed by Vectren. However, Vectren has claimed that additional resources will be needed. I am proposing to exclude these costs because they are not directly required to replace the Company's aging workforce. Instead, they are indirect costs that have not been shown to be fixed, known and measurable.

Q. Have you prepared a schedule that summarizes your recommendation with regard to energy delivery related aging workforce program costs?

A. Yes. My recommendation is presented on Schedule TSC-12. As indicated there, I am proposing to include aging workforce costs of $1,165,478. This represents a reduction of $554,102 compared to Vectren's request.

<u>Non-Incremental Labor</u>

Q. Please explain your adjustment for non-incremental labor costs.

A. In addition to its adjustments for new operation and maintenance (O&M) programs to deal with its aging workforce, Vectren has proposed a number of other adjustments seeking recognition of the cost of new programs intended to protect capital investment, improve reliability and/or increase customer service quality. For the most part, the OUCC is prepared to recognize the costs of these programs subject to certain adjustments and conditions as discussed in Ms. Soller's testimony as well as subsequently in my testimony. In addition to the programs that are specifically discussed by Ms. Soller and myself, there are several programs where the only adjustment that is being recommended is to exclude labor costs for existing employees that have been included as incremental costs for the program.

Q. Why are you proposing to exclude the labor costs associated with existing employees from the cost of these O&M programs?

A. Vectren has separately accounted for the full annualized labor costs associated with all existing employees as of March 31, 2006 (Exhibit MSH-3, Adjustment A15) and with anticipated head count additions through March 31, 2007 (Exhibit MSH-3, Adjustment A21). Therefore, the Company has already accounted for and included in the cost of service the full annual labor cost for all existing employees. Therefore, the labor cost for existing employees included in the cost of new O&M programs does not represent an incremental expense and it would be improper to include this internal labor as an additional cost for the new O&M programs.

Q. What programs are you proposing to adjust to exclude labor costs for existing employees?

A. As shown on Schedule TSC-13, I have adjusted Vectren's claimed costs for the following programs to exclude non-incremental labor expense:

- Distribution operations and training;
- Boiler systems maintenance;
- Underground facilities maintenance; and
- Reliability planning.

The total effect of removing the labor cost for existing employees from these program costs is a reduction in O&M expense of $220,068.

Ongoing MISO Day 2 Costs

Q. How did Vectren develop its estimate for the pro forma level of ongoing MISO Day 2 costs?

A. Vectren based its claim for the ongoing level of MISO Day 2 costs on the actual costs for the twelve months ended March 31, 2006, adjusted to include revenue sufficiency guarantee (RSG) costs outside the benchmark and to include uninstructed deviation costs and annual software fees that were not included in the actual costs. This resulted in a pro forma expense claim of $5,420,266.

Q. How are you proposing to determine MISO Day 2 costs?

A. I am proposing to establish the ongoing level of MISO Day 2 costs on the actual level of such costs for the 12 months ended December 31, 2006, the most recent 12 months for which data was available to me. During 2006, MISO Day 2 costs were substantially below their level in 2005. As discussed in more detail in the response to OUCC-296, the primary cause of the reduction is the decline in Revenue Inadequacy Uplift charges because "[t]he maturity of the market and better participant knowledge has led to better market operations and therefore this cost reduction." Based on this response, costs for the 12 months ended December 2006 are clearly more representative of ongoing costs than those incurred during the last nine months of 2005 and the first three months of 2006.

Q. What is the effect of your recommendation?

A. As shown on Schedule TSC-14, MISO Day 2 costs for the 12 months ending December 31, 2006 were $2,668,969. This represents a reduction of $2,751,297 in Vectren's claim based on the 12 months ending March 31, 2006.

Deferred MISO Day 2 Costs

Q. What adjustments are you proposing to make to Vectren's claim for deferred MISO Day 2 costs?

A. In its filing, Vectren developed an estimate of the balance of deferred MISO Day 2 costs as of March 31, 2007 and has proposed to amortize those costs over three years. I have made two changes to the Company's claim for deferred MISO Day 2 costs. First, I have updated the projection of the balance as of March 31, 2007 to reflect actual costs through December 31, 2006 plus additional costs for the first three months of 2007 based on the average monthly cost in 2006. Vectren based the deferral for the 12 months ended March 31, 2007 on its estimate of the going level of costs. Because actual costs in 2006 have been well below the historical levels used by Vectren, as discussed previously, this adjustment reduces the deferred balance at March 31, 2007 by approximately $2.06 million.

Second, I am proposing to amortize the March 31, 2007 estimated balance over four years rather than three, as proposed by Vectren. The Company indicated that the three-year amortization period was in accordance with Cause No. 42962. However, it is my understanding that Cause No. 42962 provided for deferral of the costs to the extent established in Cause No. 42685 and that there was no specific amortization period established by either order. My proposal to amortize deferred MISO Day 2 costs over four years is consistent with the four-year period established for MISO Day 1 costs in Cause Nos. 42257 and 42266.

Q. What is the effect of your two changes on the amortization of deferred MISO Day 2 costs?

A. As shown on Schedule TSC-15, I am recommending an annual amortization expense for MISO Day 2 costs of $2,997,298. This represents a reduction of $1,685,525 compared to the annual amortization expense requested by Vectren.

Deferred MISO Day 1 Costs

Q. What claim has Vectren made for the recovery of deferred MISO Day 1 costs?

A. Vectren is seeking to amortize the projected balance of deferred MISO Day 1 costs as of March 31, 2007 over four years. The Company projected the balance as of March 31, 2007 by adding the projected MISO Day 1 administrative costs plus FERC Assessment Fees for the 12 months ended March 31, 2007 to the deferred balance of those same two costs as of March 31, 2006.

Q. What adjustments are you proposing to make to the Company's claim?

A. I am proposing two modifications to the balance of costs eligible for deferral and recovery. First, the October 31, 2002 Stipulation and Settlement Agreement in Cause Nos. 42257 and 42266 as approved by the IURC on December 11, 2002 (the 2002 Settlement) established December 31, 2006 as the cut-off date for deferring MISO Day 1 Administrative Adder Costs. Accordingly, I have adjusted the deferred balance subject to deferral to exclude the amounts included by the Company for the first three months of 2007.

Second, I have excluded FERC Assessments from the balance of costs eligible for deferral and amortization. The Company and the other Joint Petitioners involved in the 2002 Settlement had sought approval for deferral of the Administrative Adder Costs incurred as the result of taking transmission service under the Open Access Transmission

Tariff (OATT) of the MISO which began operations near the end of 2001. The FERC Assessment fee already existed prior to the formation of the MISO and Vectren was already paying those fees. Therefore, even though the MISO began collecting FERC Assessment Fees under Schedule 10-FERC in late 2003, the FERC Assessment Fee was not a new MISO administrative cost. Accordingly, the FERC Assessment Fees for 2004, 2005 and 2006 that Vectren has included in the deferred balance should be excluded.

Q. Does this have any effect on the ongoing level of MISO Day 1 costs to be included in rates?

A. No. FERC Assessment Fees are an ongoing cost which are eligible for recovery. They were just not a new cost that resulted from taking transmission service from MISO and, in turn, became eligible for deferral and recovery under the 2002 Settlement.

Q. Have you prepared a schedule that shows the derivation of your adjustment to the amortization of deferred MISO Day 1 costs?

A. Yes. Schedule TSC-16 shows my adjustment to the amortization of deferred MISO Day 1 costs to exclude FERC Assessment Fees and to limit the deferral period to December 31, 2006. In addition, I have also made a correction to remove a $10,000 expense that was misclassified and included in the deferred balance as of March 31, 2006. As shown on Schedule TSC-16, I have estimated the balance of deferred MISO Day 1 costs eligible for recovery as of December 31, 2006 to be $4,793,841. This results in an annual amortization expense of $1,198,460 over the four-year period called for in the 2002 Settlement. This represents a reduction of $303,234 in the amortization expense claimed by Vectren.

Q. Do you have any other comments with regard to deferred MISO Day 1 and Day 2 costs?

A. Yes. The balances of deferred MISO Day 1 and Day 2 costs as of December 31, 2006 and March 31, 2007, respectively, are both estimates. Subject to review, it would be appropriate to update to recognize actual balances, consistent with the principles regarding eligible costs that I have discussed.

Environmental Chemicals

Q. How did Vectren develop its pro forma environmental chemicals expense claim?

A. Vectren adjusted test year environmental chemical quantities to reflect average projected chemical costs for the years 2007 through 2009. In developing this pro forma claim, Vectren reflected a constant normalized level of usage of lime, soda ash and limestone in all three years. Ammonia usage was projected to increase from 15,300 tons in both 2007 and 2008 to 26,780 tons in 2009 based on the assumption that the scrubbers at A. B. Brown Units 1 and 2 and Warrick would all operate for all 12 months in 2009. Vectren also reflected projected increases in prices from year to year. Overall, the Company projected chemical costs (excluding $80,000 for sulphur) to increase from $12.48 million in 2007 to $13.18 million in 2008, to $15.55 million in 2009. The Company's pro forma expense claim based on the three-year average is $13.74 million (excluding sulphur costs).

Q. How are you proposing to establish the pro forma level of environmental chemicals expense?

A. I am proposing to base the pro forma allowance for environmental chemicals expense on the Company's estimate of normalized levels of chemical usage for 2007 and contract prices for 2007. As shown on Schedule TSC-17, this results in normalized chemical costs for 2007 of $12,543,816. This represents a reduction of $1,193,928 compared to Vectren's claim based on a projection of average annual costs for the years 2007 through 2009, which is not fixed, known and measurable.

Catalyst Expense

Q. What claim has the Company made for catalyst expense?

A. In its filing, Vectren has requested a total of $2,540,000 catalyst costs. This includes $1,200,000 for Culley Unit 3 catalyst replacement, $1,229,000 for Warrick 4 catalyst regeneration and $111,000 for Culley Unit 3 fabric filter expense.

Q. What adjustment are you proposing to make to this claim?

A. I am proposing to adjust catalyst expense to a pro forma level of $1,863,500. As shown on Schedule TSC-18, this represents a reduction of $676,500 compared to Vectren's claim.

Q. What is the basis for your recommendation?

A. According to the response to OUCC-102, Vectren expects to spend $1,200,000 for catalyst replacement in 2007 and 2008 at A. B. Brown Units 2 and 1, respectively, which is consistent with the $1.2 million for catalyst replacement at Culley Unit 3 in 2006 that was included in Vectren's claim. Accordingly, I have included $1.2 million for catalyst replacement as an element of pro forma expense.

According to the response to OUCC-299, rather than spending the $1,229,000 included in its filed claim for Warrick 4 catalyst regeneration, Vectren spent $323,000 in 2006. That response also states that the Company now expects to spend $552,500 to replace and install Warrick 4 catalyst in 2007. I have included the higher projected cost of $552,500 in 2007 as an element of pro forma expense.

Finally, the $111,000 included for the Culley Unit 3 fabric filter is an estimated annual expense for the new equipment. I have accepted this estimate as an element of pro forma catalyst expense. As shown on Schedule TSC-18, these three elements result in a total normalized expense of $1,863,500.

Substation Inspection and Maintenance Expense

Q. Please explain your adjustment to substation inspection and maintenance expense.

A. I have adjusted Vectren's claim for increased spending on substation inspection and maintenance programs to reflect the adjustments recommended by Ms. Soller on behalf of the OUCC. As shown on Schedule TSC-19, Ms. Soller is recommending an allowance for incremental substation inspection and maintenance costs of $325,000 in this proceeding. This represents a reduction of $576,995 compared to Vectren's request.

Line Clearance Expense

Q. What adjustment are you proposing to make to line clearance expense?

A. In its filing, Vectren has proposed an increase in test year line clearance expense of $1,860,232 to move to a five-year cycle for distribution line clearance. (An additional $20,000 new transmission build out was also requested.) In response to OUCC-121, the Company indicated that the total amount required for distribution and transmission line clearance is $3.50 million and, that during the test year, actual expenditures were $1.867 million. Based on this information, the required increase to achieve a five-year time cycle is $1.633 million. Accordingly, I have adjusted line clearance expense to exclude the difference between the $1,860,232 increase recognized by Vectren and the $1,633,000 increase in test year spending necessary to move to the required $3.5 million total program cost.[1] As shown on Schedule TSC-20, this adjustment reduces pro forma line clearance expense by $227,232.

Overhead Facilities Maintenance

Q. Please explain what adjustments to overhead facilities maintenance expense you are proposing to recognize.

A. Schedule TSC-21 sets forth the differences between to OUCC's recommendation regarding additional overhead facilities maintenance costs and Vectren's pro forma request. The adjustments to the Company's claimed additional costs are explained in the testimony of Ms. Soller. As shown on Schedule TSC-21, the OUCC is recommending an allowance for incremental overhead facilities maintenance programs of $1,867,223. This represents a reduction of $1,293,512 compared to Vectren's request of $3,160,735 for such new programs.

Uncollectibles Expense

Q. What adjustment are you proposing to make to uncollectibles expense?

A. Vectren has calculated its claim for uncollectible accounts by multiplying going level revenues at present rates by a historical average ratio of net write-offs to revenues.[2] Vectren utilized the five years ending with the test year to calculate its ratio of net write-offs to revenues. Instead of utilizing a five-year ratio of net write-offs to revenues, I am proposing to utilize the three years ending with the test year to calculate the ratio.

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[1] The $1.633 million increase that I have included is consistent with $1.60 million estimated increase identified on the workpaper supporting Adjustment A35 at MSFR-3680-168 of 1050. Although $1.60 million is identified as the incremental expense, $1,860,232 has been included as the pro forma increase in Adjustment A35.

[2] Uncollectibles associated with the revenue increase in rates are separately accounted for in the calculation of the necessary revenue increase.

Q. Why are you proposing to utilize the three-year average rather than the five-year average ratio of net write-offs to revenues?

A. For the 12 months ended March 2002 and March 2003, the ratios of net write-offs to revenues (uncollectible ratios) were 0.58 percent and 0.65 percent, respectively. In the three subsequent 12-month periods ending March of 2004, 2005 and 2006, the ratios were 0.36 percent, 0.15 percent and 0.39 percent. To determine whether Vectren had undertaken actions that would have help achieve these reductions, OUCC-263 asked what steps the Company had undertaken in the last three years or currently has under consideration to improve collections and minimize bad debt. In response, Vectren stated:

> Vectren has implemented a number of initiatives over the last few years aimed at controlling the level of uncollectible expense. These initiatives include engaging an outside firm (PAR 3) specializing in automated calling for payment management to make pre-disconnect calls to customers to encourage timely payment, implementing positive identification and credit verification upon account initialization using tools such as Equifax, and requiring paid deposits from new customers failing to meet IURC approved deposit requirements as well as from customers with a previous non-payment history. Vectren adjusted processes in 2003 to more effectively utilize our customer information system to identify customers with previous written off accounts that are requesting current service. In early 2006, Vectren also engaged an outside firm to utilize our customer information system to identify existing customers with previous written off accounts and transfer the balance to the existing account.
>
> Vectren disconnection activity increased 6% in calendar year 2005 versus 2004 and has increased 7% year-to-date June 2006 versus year-to-date June 2005. Vectren made improvements to the work scheduling system to prioritize disconnection activity in order to reduce bad debt risk.

In addition, the response to OUCC-264 indicated that in the last five years, Vectren has also implemented changes to the procedures for collecting deposits. These include: requiring deposits to be paid in advance before service is reconnected following disconnection for non-payment; requiring deposits of twice the average monthly bill for residential and twice the highest monthly bill for commercial customers; and requiring commercial/industrial customers with a poor payment history to establish a deposit.

Based on the actions that Vectren indicates that it has undertaken over the past several years, it is reasonable to expect that the lower uncollectible ratios that have been experienced recently are the result of those actions. Therefore, the use of the three-year average uncollectibles ratio is more appropriate than the five-year historical ratio as a measure of the ongoing level of uncollectibles expense.

Q. What is the effect of utilizing the three-year ratio rather than the five-year ratio?

A. The three-year ratio of net write-offs to revenue is 0.26 percent. As shown on Schedule TSC-22, applying this ratio to pro forma revenues at present rates produces an allowance for uncollectibles expense of $1,072,916. This represents a reduction of $495,191 compared to Vectren's claim.

Meter Reading Expense

Q. Please explain your adjustment to meter reading expense.

A. Vectren has claimed a pro forma increase in meter reading expense of $39,467 to recognize the cost of additional meter reads due to customer growth and increased meter reader incentives to identify fraud and diversion subsequent to the test year. In response to OUCC-69, Vectren has indicated that the correction of non-registering meters and elimination of diversion that were produced by meter reader incentives resulted in estimated increased revenues during the test year of over $230,000. Because the correction of additional non-registering meters and the elimination of additional fraud and diversions will result in incremental revenues that can be expected to far exceed the increase in meter reading costs, I have eliminated Vectren's pro forma increase in meter reading costs. As shown on Schedule TSC-23, this adjustment reduces pro forma expense by $39,467.

Advertising Expense

Q. Please summarize Vectren's adjustment to test year informational and instructional advertising expense.

A. During the test year, Vectren spent $60,767 on customer communications/ advertising. The Company has requested a $400,000 increase for additional customer education/safety campaigns and programs. Of this total increase, $120,000 is to be spent on a new school utility safety program. The remainder is for direct mail, radio, TV and newspaper advertising and the associated creation and production costs.

Q. What is your recommendation regarding the claimed increase in advertising expense?

A. I am proposing to include the $120,000 that Vectren has requested for the new school utility safety program. However, I am recommending that the remaining increase in advertising expense requested by Vectren be eliminated. These costs are neither fixed, known and measurable nor are they costs that are essential new programs for protecting capital investment, improving reliability or increasing the quality of service. As shown on Schedule TSC-24, this adjustment reduces pro forma advertising expense by $280,000.

Property and Risk Insurance

Q. Please explain your adjustment to property and risk insurance expense.

A. In its filing, the Company adjusted test year property and risk insurance to a projected pro forma level by applying various escalation rates to the test year insurance premiums. In response to OUCC-43, the Company provided the actual 2006-2007 premiums for its various property and risk insurance policies. I have used these premiums to develop the ongoing annual cost of property and risk insurance of $2,364,597 as shown on Schedule TSC-25. This represents a reduction of $663,506 compared to Vectren's projection of $3,028,103.

Injuries and Damages Expense

Q. Please summarize Vectren's claim for injuries and damages expense.

A. Vectren's claim for injuries and damages expense consists of two components. First, the Company has included a three-year average of actual claims paid for the 12-month periods ended March 31 of 2004, 2005 and 2006. Second, the Company has included the amortization of two major claims totaling $975,000 that were accrued as an expense, but not paid, during the test year, Vectren has proposed to amortize these major claim accruals over three years.

Q. What is the status of the two major injuries and damages claims?

A. In January 2007, one of the two major claims was settled for a payment of $400,000. According to the response to OUCC-302, the other matter has not been resolved and it is unknown when or in what amount any payment will be made on that second claim.

Q. What adjustment are you proposing to make to injuries and damages expense?

A. I am proposing to adjust injuries and damages expense to exclude the recovery of the major injury and damage claim that has not been paid. This amount is not fixed, known and measurable. With regard to the major claim that has been paid, I am proposing to amortize the payment over five years rather than three years in order to minimize the rate impact and consistent with the fact that it is not a routine claim of the type that is included in the three-year average. As shown on Schedule TSC-26, this adjustment reduces injuries and damages expense by $245,000.

Outside Services

Q. What adjustment are you proposing to make to outside services expense?

A. I am proposing to adjust outside services to exclude two items that are not properly recovered from ratepayers. First, I have excluded $10,583 paid to Political Action Committee for managing employee PAC contributions, ensuring compliance with campaign finance laws and supporting Vectren Corporate goals with regard to regulatory policy and laws. Second, I have excluded $43,766 paid for legal services related to bankruptcy of a non-utility investment that were incorrectly charged to electric operations. (Response to OUCC-244) As shown on Schedule TSC-27, this adjustment reduces test year expense by $54,359.

Asset Charge

Q. Please explain your adjustment to the asset charge from Vectren Utilities Holdings, Inc.

A. Vectren pays an asset charge to Vectren Utilities Holdings, Inc. (VUHI) for the use of the information technology assets owned by VUHI. This asset charge includes the depreciation, property taxes, return and income taxes on those assets. Vectren has calculated the return and income tax component of the pro forma asset charge based on the Company's claimed cost of capital. To develop the OUCC's recommended cost of service, I have adjusted the asset charge to reflect the overall rate of return recommended by OUCC witness Woolridge. As shown on Schedule TSC-28, this change reduces the asset charge by $739,900. Ultimately, the asset charge should be based on the rate of return approved by the Commission.

Depreciation Expense

Q. What adjustment have you made to depreciation expense?

A. I have adjusted depreciation expense to incorporate Dr. Ileo's recommendations on behalf of the OUCC. As shown on Schedule TSC-29, this adjustment reduces depreciation expense by $2,538,945.

Indiana Utility Receipts Tax

Q. What adjustment have you made to the pro forma allowance for Indiana utility receipts taxes?

A. The Indiana Utility Receipts Tax (IURT) is determined based on revenues net of uncollectibles. Therefore, I have adjusted the level of IURT at present rates to reflect my adjustment to uncollectibles expense. As shown on Schedule TSC-30, this adjustment increases the IURT at present rates by $6,933.

Q. Have you made any other changes to the calculation of the IURT?

A. Yes. In determining the revenue increase necessary to generate its requested rate of return, Vectren included both uncollectibles expense and IURT in the revenue conversion factor used to calculate the required revenue increase. However, the Company did not recognize that the uncollectibles associated with the revenue increase should be netted out of the increase in revenue for purposes of calculating the revenue increase subject to the IURT. I have revised the calculation of the revenue conversion factor to recognize that uncollectibles are not subject to the IURT.

LP-1 Revenue Credits

Q. Please explain what LP-1 revenue credits are and how Vectren treated those credits in its filing.

A. Customers served under Vectren's Rate LP (Large Power Service) are eligible for a credit pursuant to Rider LP-1 (Efficiency Incentive Rider) for new electrical loads that meet certain conditions (Tariff Sheet No. 53). The LP-1 credit is provided for the first 36 months of the new service. During the test year ended March 31, 2006, these credits totaled $1,765,141. In its filing, Vectren has adjusted its pro forma revenues to eliminate those LP-1 credits that expired during the test year. As a result, the Company's pro forma claim for LP-1 revenue credits is $500,814. This claim consists of credits to three customers which expire as follows:

January 1, 2007	$ 8,909
June 1, 2007	443,206
October 1, 2007	48,699
	$500,814

Q. Are you proposing to increase revenues to reflect the expiration of any of these additional credits?

A. No. To be consistent with my recommendations to limit costs to known levels as of no later than March 31, 2007, I have not made any adjustment to revenues to recognize the expiration of the remaining LP-1 credits. (Although the credit that expired on January 1, 2007 meets the March 31, 2007 cut-off, the amount is small and I have not adjusted for this credit.) However, if cost increases subsequent to March 31, 2007 are recognized, it would be appropriate to include the additional revenues that result from the expiration of the remaining LP-1 credits.

Interest Synchronization

Q. Please explain your adjustment to Synchronize interest expense.

A. To determine the interest deduction for income tax purposes, I have multiplied the OUCC's recommended rate base by the weighted cost of debt included in the capital structure recommended by Dr. Woolridge. This procedure synchronizes the interest deduction for income tax purposes with the interest component of the return on rate base to be recovered from ratepayers. As shown at the bottom of Schedule TSC-4, this adjustment increases the interest deduction by $588,982 compared to the synchronized interest deduction recognized by Vectren. This reduces state income taxes by $50,063 and federal income taxes by $188,621.

Comparison of Positions

Q. Please summarize Schedule TSC-31.

A. Schedule TSC-31 provides a comparison of the adjustments to operating income at present rates as filed by Vectren and as recommended by the OUCC. In developing this schedule, I have not separately listed each of Vectren's and the OUCC's adjustments to revenue because there are no differences in our adjustments. For fuel and purchased power, I have only separately identified fuel handling and MISO Day 2 costs because those are the only fuel and purchased power related differences in our adjustments. I have separately listed all of the other adjustments to operating expenses.

Q. Please explain Schedule TSC-32.

A. Schedule TSC-32 provides a comparison of the calculation of the increase in revenues as requested by Vectren and as recommended by the OUCC. This schedule serves to summarize the differences in rate base, rate of return, operating income and the revenue conversion factor between the Company and the OUCC.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. (VECTREN) FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICES	)))))))	CAUSE NO. 43111

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY

OF

THOMAS S. CATLIN

ON BEHALF OF THE

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

FEBRUARY 27, 2007

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
Columbia, Maryland 21044

VECTREN SOUTH
Electric Tariff

Summary of Operating Income
Test Year Ending March 31, 2006

	Company Amounts at Present Rates	OUCC Adjustments	Amounts per OUCC at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Increase
Operating Revenue	$ 412,659,811	$ -	$ 412,659,811	$ 51,414,445	$ 464,074,256
Operating Revenue Deductions					
Fuel and Purchased Power	163,335,325	(4,769,213)	158,566,112	-	158,566,112
Operation & Maintenance Expense	129,460,116	(10,227,841)	119,232,275	190,233	119,422,508
Asset Charge	8,973,132	(739,900)	8,233,232	-	8,233,232
Depreciation Expense	64,494,881	(2,538,945)	61,955,936	-	61,955,936
Taxes Other Than Income	13,929,391 (1)	6,933	13,936,324	717,931	14,654,254
Total Operating Revenue Deductions	$ 380,192,845	$ (18,268,966)	$ 361,923,879	$ 908,164	$ 362,832,043
Operating Income Before Taxes	$ 32,466,966	$ 18,268,966	$ 50,735,932	$ 50,506,280	$ 101,242,213
Income Taxes					
State Income Tax	1,325,265	$ 1,503,388	2,828,653	4,354,058	7,182,711
Federal Income Tax	1,687,545	5,661,809	7,349,354	16,153,278	23,502,632
Total Income Taxes	$ 3,012,810 (2)	$ 7,165,197	$ 10,178,007	$ 20,507,336	$ 30,685,343
Utility Operating Income	$ 29,454,156	$ 11,103,770	$ 40,557,926	$ 29,998,945	$ 70,556,870
Rate Base	$ 1,017,759,887	24,439,083	$ 1,042,198,970		$ 1,042,198,970
Rate of Return	2.89%		3.89%		6.77%

Notes:
(1) Reflects correction of $(35) to match amounts on MSH-3, Adjustments A-63 and A-64.

(2) Reflects correction of $95,857 to match amounts on MSH-3, Adjustments A-60, A-61 and A-62.

VECTREN SOUTH
Electric Tariff

Determination of Revenue Increase/(Decrease)
Test Year Ending March 31, 2006

		Amount	Source
OUCC Recommended Rate Base		$ 1,042,198,970	Schedule TSC-2
Required Rate of Return		6.77%	Exhibit_(JRW-1)
Net Operating Income Required		$ 70,556,870	
Net Operating Income at Present Rates		40,557,926	Schedule TSC-3
Required Increase in Net Operating Income		$ 29,998,945	
Revenue Multiplier		1.71388	See Note (1)
Revenue Increase/(Decrease)		$ 51,414,445	
Revenue Increase/(Decrease)		$ 51,414,445	
Uncollectibles	0.26%	133,678	
Base for Indiana Utility Receipts Tax		51,280,767	
Indiana Utility Receipts Tax	1.40%	717,931	
IURC Fee	0.11%	56,556	
Subtotal		$ 50,506,280	
State Taxable Income		$ 51,224,211	
State Income Tax	8.50%	4,354,058	
Federal Taxable Income		$ 46,152,222	
Federal Income Tax	35.00%	16,153,278	
Net Income Surplus/(Deficiency)		$ 29,998,945	

Note:

(1) Calculation of Conversion Factor

Revenues		1.00000
Bad Debt		0.00260
Base for Indiana Utility Receipts Tax	0.99740	
Indiana Utility Receipts Tax	0.01400	0.01396
IURC Fee		0.00110
Subtotal		0.98234
Net State Taxable Income	0.99630	
SIT Rate	0.08500	
State Income Tax		0.08469
Net Federal Taxable Income	0.89765	
FIT Rate	0.35000	
Federal Income Tax		0.31418
Revenue Conversion Factor		0.58347
Revenue Multiplier		1.71388

VECTREN SOUTH
Electric Tariff

Summary of Rate Base
Test Year Ending March 31, 2006

Description	Amount Per Company Filing	OUCC Adjustments	Adjusted Per OUCC
Electric Plant in Service	$ 1,287,918,382	$ 24,105,297	$ 1,312,023,679
Completed Not Classified	380,787,447	40,403,849	421,191,296
Fabric Filter at Culley Unit 3 (est.)	49,000,000	-	49,000,000
Transmission Plant Additions (est.)	16,977,000	(16,977,000)	-
Total Plant	$ 1,734,682,829	$ 47,532,146	$ 1,782,214,975
Accumulated Depreciation	(784,045,954)	(28,762,766)	(812,808,720)
Net Utility Plant	$ 950,636,875	$ 18,769,380	$ 969,406,255
Materials & Supplies	37,897,926	5,089,294	42,987,220
DSM-Post 1994 Regulatory Asset	26,777,987	833,716	27,611,703
DSM-Post 1994 Regulatory Asset	1,791,376	(247,499)	1,543,877
MISO Day 2 Startup Costs	655,724	(5,808)	649,916
Total Rate Base	$ 1,017,759,887	$ 24,439,083	$ 1,042,198,970

VECTREN SOUTH
Electric Tariff

Summary of Adjustments to Rate Base
Test Year Ending March 31, 2006

	Amount	Source
Rate Base per Company Filing	$ 1,017,759,887	Exhibit MSH-3, Page 2.
OUCC Adjustments		
Update Rate Base Components	24,439,083	Schedule TSC-5
Total OUCC Adjustments	$ 24,439,083	
OUCC Adjusted Rate Base	$ 1,042,198,970	

VECTREN SOUTH
Electric Tariff

Summary of Adjustments to Net Income
Test Year Ending March 31, 2006

	Amount	Source
Net Income per Company	$ 29,454,156	Exhibit MSH-2
OUCC Adjustments		
Fuel Handling Expense	197,690	Schedule TSC-6
Restricted Stock Expense	278,643	Schedule TSC-7
Incentive Compensation	478,216	Schedule TSC-8
Actual Incremental Employee Headcount	885,700	Schedule TSC-9
Payroll Tax Adder	(5,221)	Schedule TSC-10
Aging Workforce-Power Supply	331,614	Schedule TSC-11
Aging Workforce-Energy Delivery	329,552	Schedule TSC-12
Non-Incremental Labor	130,885	Schedule TSC-13
MISO Day 2 Ongoing Expense	1,636,334	Schedule TSC-14
Miso Day 2 Deferred Costs	1,002,466	Schedule TSC-15
Miso Day 1 Deferred Costs	180,348	Schedule TSC-16
Environmental Chemicals Expense	710,088	Schedule TSC-17
Catalyst Expense	402,348	Schedule TSC-18
Substation Painting Expense	343,168	Schedule TSC-19
Line Clearance Expense	135,146	Schedule TSC-20
Overhead Facilities Maintenance	825,338	Schedule TSC-21
Uncollectibles	294,515	Schedule TSC-22
Meter Reading	23,473	Schedule TSC-23
Advertising	166,530	Schedule TSC-24
Property and Risk Insurance Expense	394,620	Schedule TSC-25
Injuries & Damages	145,714	Schedule TSC-26
Outside Services	32,330	Schedule TSC-27
Asset Charge	440,055	Schedule TSC-28
Depreciation Expense	1,510,038	Schedule TSC-29
Indiana Utility Receipts Tax	(4,506)	Schedule TSC-30
Interest Synchronization	238,685	Schedule TSC-4
Total OUCC Adjustments	$ 11,103,770	
OUCC Adjusted Net Income	$ 40,557,926	

VECTREN SOUTH
Electric Tariff

Summary of Adjustments to Net Income
Test Year Ending March 31, 2006

	Revenues	O&M Expenses	Depreciation Expense	Taxes Other Than Income	State Income Tax	Federal Income Tax	Net Operating Income
Net Income per Company	$ 412,659,811	$ 301,768,573	$ 64,494,881	$ 13,929,391	$ 1,325,265	$ 1,687,545	$ 29,454,156
OUCC Adjustments							
Fuel Handling Expense	-	(332,391)	-	-	28,253	106,448	197,690
Restricted Stock Expense	-	(468,504)	-	-	39,823	150,038	278,643
Incentive Compensation	-	(804,062)	-	-	68,345	257,501	478,216
Actual Incremental Employee Headcount	-	(1,489,197)	-	-	126,582	476,915	885,700
Payroll Tax Adder	-	8,778	-	-	(746)	(2,811)	(5,221)
Aging Workforce-Power Supply	-	(557,569)	-	-	47,393	178,562	331,614
Aging Workforce-Energy Delivery	-	(554,102)	-	-	47,099	177,451	329,552
Non-Incremental Labor	-	(220,068)	-	-	18,706	70,477	130,885
MISO Day 2 Ongoing Expense	-	(2,751,297)	-	-	233,860	881,103	1,636,334
Miso Day 2 Deferred Costs	-	(1,685,525)	-	-	143,270	539,789	1,002,466
Miso Day 1 Deferred Costs	-	(303,234)	-	-	25,775	97,111	180,348
Environmental Chemicals Expense	-	(1,193,927)	-	-	101,484	382,355	710,088
Catalyst Expense	-	(676,500)	-	-	57,503	216,649	402,348
Substation Painting Expense	-	(576,995)	-	-	49,045	184,783	343,168
Line Clearance Expense	-	(227,232)	-	-	19,315	72,771	135,146
Overhead Facilities Maintenance	-	(1,387,705)	-	-	117,955	444,413	825,338
Uncollectibles	-	(495,191)	-	-	42,091	158,585	294,515
Meter Reading	-	(39,467)	-	-	3,355	12,639	23,473
Advertising	-	(280,000)	-	-	23,800	89,670	166,530
Property and Risk Insurance Expense	-	(663,506)	-	-	56,398	212,488	394,620
Injuries & Damages	-	(245,000)	-	-	20,825	78,461	145,714
Outside Services	-	(54,359)	-	-	4,621	17,408	32,330
Asset Charge	-	(739,900)	-	-	62,891	236,953	440,055
Depreciation Expense	-	-	(2,538,945)	-	215,810	813,097	1,510,038
Indiana Utility Receipts Tax	-	-	-	6,933	-	(2,426)	(4,506)
Interest Synchronization	-	-	-	-	(50,063)	(188,621)	238,685
Total OUCC Adjustments	$ -	$ (15,736,954)	$ (2,538,945)	$ 6,933	$ 1,503,388	$ 5,661,809	$ 11,103,770
OUCC Adjusted Net Income	$ 412,659,811	$ 286,031,619	$ 61,955,936	$ 13,936,324	$ 2,828,653	$ 7,349,354	$ 40,557,926

VECTREN SOUTH
Electric Tariff

Calculation of State and Federal Income Tax
Test Year Ending March 31, 2006

	Amount per Company at Present Rates	OUCC Adjustments	Adjusted Per OUCC at Present Rates	Revenue Increase/ (Decrease)	Amounts After Revenue Increase
Operating Income before Income Taxes	$ 32,466,966	$ 18,268,966	$ 50,735,932	$ 50,506,280	$ 101,242,213
Adjustments					
Interest Expense	(24,528,013)	(588,982)	(25,116,995)	-	(25,116,995)
Book Depreciation on Non-Deferred Basis	2,037,536	-	2,037,536	-	2,037,536
Medicare Act Subsidy	(182,004)	-	(182,004)	-	(182,004)
Other Non-Deductible Expenses	39,539	-	39,539	-	39,539
Indiana Utility Receipts Tax	5,755,270	6,933	5,762,203	717,931	6,480,133
Total Adjustments	$ (16,877,672)	$ (582,049)	$ (17,459,722)	$ 717,931	$ (16,741,791)
Income Subject to State Income Tax	$ 15,589,294	$ 17,686,917	$ 33,276,211	$ 51,224,211	$ 84,500,422
Indiana State Income Tax at 8.50%	$ 1,325,090	$ 1,503,388	$ 2,828,478	$ 4,354,058	$ 7,182,536
Kentucky Minimum Tax	175	-	175	-	175
Total State Ioncome Taxes	$ 1,325,265	$ 1,503,388	$ 2,828,653	$ 4,354,058	$ 7,182,711
Operating Income before Income Taxes	$ 32,466,966	$ 18,268,966	$ 50,735,932	$ 50,506,280	$ 101,242,213
Adjustments					
Interest Expense	(24,528,013)	(588,982)	(25,116,995)	-	(25,116,995)
Book Depreciation on Non-Deferred Basis	2,037,536	-	2,037,536	-	2,037,536
Special Deduction for Qualified Production Facilities	(512,514)		(512,514)	-	(512,514)
Medicare Act Subsidy	(182,004)	-	(182,004)	-	(182,004)
Other Non-Deductible Expenses	39,539	-	39,539	-	39,539
State Income Tax	(1,325,265)	(1,503,388)	(2,828,653)	(4,354,058)	(7,182,711)
Total Adjustments	$ (24,470,721)	$ (2,092,370)	$ (26,563,091)	$ (4,354,058)	$ (30,917,149)
Income Subject to Federal Income Tax	$ 7,996,245	$ 16,176,597	$ 24,172,841	$ 46,152,222	$ 70,325,064
Federal Income Tax at 35%	$ 2,798,686	$ 5,661,809	$ 8,460,494	$ 16,153,278	$ 24,613,772
Amortization of ITC	(1,111,141)	-	(1,111,141)	-	(1,111,141)
Net Federal Income Tax	$ 1,687,545	$ 5,661,809	$ 7,349,353	$ 16,153,278	$ 23,502,631

Calculation of Interest Deduction					
Rate Base	$ 1,017,759,887		$ 1,042,198,970		$ 1,042,198,970
Weighted Cost of Debt	2.41%		2.41%		2.41%
Interest Deduction	$ 24,528,013	$ 588,982	$ 25,116,995		$ 25,116,995
State Income Tax Effect at 8.50%		(50,063)			
Federal Income Tax Effect at 35%		(188,621)			
Interest Synchronization Adjustment		$ (238,685)			

VECTREN SOUTH
Electric Tariff

Adjustment to Update Rate Base Components
Test Year Ending March 31, 2006

Description	Amount Per Company Filing (1)	Amount Per Company at 10/31/2006 (2)	Adjustment
Electric Plant in Service	$ 1,287,918,382	$ 1,312,023,679	$ 24,105,297
Completed Not Classified	380,787,447	421,191,296	40,403,849
Fabric Filter at Culley Unit 3 (est.)	49,000,000	49,000,000	-
Transmission Plant Additions (est.)	16,977,000	-	(16,977,000)
Total Plant	$ 1,734,682,829	$ 1,782,214,975	$ 47,532,146
Accumulated Depreciation	(784,045,954)	(812,808,720)	(28,762,766)
Net Utility Plant	$ 950,636,875	$ 969,406,255	$ 18,769,380
Materials & Supplies	37,897,926	42,987,220	5,089,294
DSM-Post 1994 Regulatory Asset	26,777,987	27,611,703	833,716
DSM-Post 1994 Regulatory Asset	1,791,376	1,543,877	(247,499)
MISO Day 2 Startup Costs	655,724	649,916	(5,808)
Total Rate Base	$ 1,017,759,887	$ 1,042,198,970	$ 24,439,083

Notes:
(1) Company Exhibit No. MSH-3, Adjustment A41.

(2) Company Exhibit No. MSH-6.

VECTREN SOUTH
Electric Tariff

Adjustment to Remove Pro Forma Increase in
Fuel Handling Expense
Test Year Ending March 31, 2006

		Amount
Test Year Fuel Handling Expense (1)	$	4,300,756
Pro Forma Fuel Handling Expense per Company(1)		4,633,147
Adjustment to Remove Pro Forma Increase Per Company	$	(332,391)
Fuel Handling Expense for the 12 Months Ending 10/31/2006 (2)	$	4,156,680

Notes:
(1) Per Exhibit MSH-3, Adjustment A-11.

(2) Per response to OUCC-84. Provided for comparison purposes.

VECTREN SOUTH
Electric Tariff

Adjustment to Restricted Stock & Stock Option Expense
Test Year Ending March 31, 2006

	Amount
2006 Projected Restricted Stock & Stock Dividend Expense (1)	$ 861,241
Restricted Stock & Stock Dividend Expense per Filing (2)	1,329,745
Adjustment to O&M Expense	$ (468,504)

Notes:
(1) Per Response to OUCC-173.

(2) Company Exhibit MSH-3, Adjustment A16.

VECTREN SOUTH
Electric Tariff

Adjustment to Incentive Compensation Expense
Test Year Ending March 31, 2006

	Amount
2006 Projected Vectren Incentive Plan Expense (1)	$ 1,743,247
Vectren Incentive Plan Expense per Filing (2)	2,547,309
Adjustment to O&M Expense	$ (804,062)

Notes:
(1) Per Response to OUCC-174.

(2) Company Exhibit MSH-3, Adjustment A17.

VECTREN SOUTH
Electric Tariff

Adjustment to Reflect Known Changes in Employee Headcount
Test Year Ending March 31, 2006

	Direct Labor (1)	Labor Loading @ 58.5% (2)	Total Labor Costs	Vectren South % (3)	Electric % (3)	Electric Amount
Internal Auditor	$ 40,000	$ 23,400	$ 63,400	48.0%	76.0%	$ 23,128
Forecasting Manager	85,000	49,725	134,725	42.0%	76.0%	43,004
Diversion & Identity Fraud	27,000	15,795	42,795	48.0%	76.0%	15,612
Diversion & Identity Fraud	25,000	14,625	39,625	48.0%	76.0%	14,455
Customer Accounting Analyst	40,000	23,400	63,400	23.0%	57.0%	8,312
Billing Coordinator	52,000	30,420	82,420	23.0%	57.0%	10,805
MISO Supervisor	42,500	24,863	67,363	100.0%	100.0%	67,363
Increase in Labor Cost Related to Known Changes in Headcount						$ 182,679
Increase in Labor Cost Related to changes in Headcount Per Company Filing (4)						1,671,876
Adjustment to O&M Expense						$ (1,489,197)

Notes:

(1) Per Response to OUCC-37.

(2) Company Labor Loading of 59% less 0.5% VIP adder for FICA taxes. OUCC is separately accounting for the FICA for VIP.

(3) Per workpapers for Exhibit MSH-3, Adjustment A-21.

(4) Per Exhibit MSH-3, Adjustment A-21.

VECTREN SOUTH
Electric Tariff

Adjustment to Correct Payroll Tax Rate
on Direct Labor Costs not Separately Adjusted
Test Year Ending March 31, 2006

	Direct Labor	Adjustment
Pro Forma Labor - Existing Head Count (1)	$ 24,325,003	
Customer Contact Center Additional Reps. (2)	57,661	
Asset Management Program Labor (3)	10,374	
Total Labor Subject to FICA Adjustment	24,393,038	
FICA Loading Adjustment (4)	0.50%	
		$ (121,965)
Vectren Incentive Plan (5)	$ 1,743,247	
Payroll Tax Loader	7.50%	
		130,744
Adjustment to Taxes Other Than Income		$ 8,778

Notes:

(1) Company Exhibit No. MSH-3, Adjustment A15.

(2) Per response to OUCC-41.

(3) Reflects labor amounts shown on MSFR-3680-201 of 1050.

(4) Per response to OUCC-28e.

(5) Per Schedule TSC-8.

VECTREN SOUTH
Electric Tariff

Adjustment to Normalize Workforce Aging Costs-Power Supply
Test Year Ending March 31, 2006

	Amount (1)
Electrician Apprentices	$ 338,248
Repair Mechanic Apprentices	394,162
Engineering Co-op	10,971
Auxiliary Equipment Operator Apprentices	46,609
Coal Yard Operator	65,031
Subtotal	$ 855,021
Less: 0.5% Reduction in Loadings (2)	(2,689)
Supervisor Retirement Impact	44,878
Training (3)	290,885
Retirements (3)	(352,766)
Power Supply Aging Workforce Costs per OUCC	$ 835,330
Annual Aging Workforce Costs per Company	1,392,899
Adjustment to O&M Expense	$ (557,569)

Notes:

(1) Amounts per workpapers for Exhibit No. MSH-3, Adjustment A22 except where noted.

(2) Labor loadings have been reduced to reflect exclusion of 0.5% FICA adder for incentive compensation.

(3) See page 2 of this schedule.

VECTREN SOUTH
Electric Tariff

Adjustment to Normalize Workforce Aging Costs-Power Supply
Test Year Ending March 31, 2006

Power Supply Retirements (1)	Hours	Rate		Annual Amount
Electricians (2 Full Time Equivalents)	3,968	28.57	$	113,366
Labor Loadings @ 58.5%				66,319
Total Savings (100% O&M)			$	179,685
Repair Mecahanic Apprentices (2 Full Time Equivalents)	3,968	27.52	$	109,199
Labor Loadings @ 58.5%				63,882
Total Savings (100% O&M)			$	173,081
Total Savings due to Retirements			$	352,766
Training Program Costs (2)				
Plant Operations Subject Matter Expert	1,984	29.82	$	59,163
Labor Loadings @ 58.5%				34,610
Total Expense			$	93,773
Electrical/Mechanical Subject Matter Expert	1,984	28.57		56,683
Labor Loadings @ 58.5%				33,159
Total Expense			$	89,842
CAD Technician	1,984	15.00		29,760
Labor Loadings @ 58.5%				17,410
Total Expense			$	47,170
Critical Thinking Training (3)			$	60,100
Total Training Program Costs per OUCC			$	290,885

Notes:
(1) Rates and O&M percentages per response to OUCC-250b. Loading factor reflects exclusion of FICA adder of 0.5% for incentive compensation.

(2) Rates per response to OUCC-95b. Loading factor reflects exclusion of 0.5% FICA adder for incentive compensation.

(3) Per Vectren informal presentation to OUCC of January 18, 2007.

VECTREN SOUTH
Electric Tariff

Adjustment to Normalize Workforce Aging Costs-Energy Delivery
Test Year Ending March 31, 2006

	Amount (1)
Electric Supervisor (1 FTE)	$ 66,780
Training Manager (1FTE)	16,593
Technical Taining Consultants (2 FTE)	190,800
Line Specialist Apprentices (8 FTE)	386,628
Electrician Apprentices (2FTE)	142,065
Engineering Co-ops (2FTE)	21,942
Reduction Due to Retirements	(231,710)
Subtotal	$ 593,098
Less: 0.5% Reduction in Loadings (2)	(1,865)
Electrician Apprentice Training and Development (3)	141,500
Supervisor Retirement Impact	34,969
Contract Labor for Line Specialists	339,406
Contract Labor for Substation Electricain	58,370
Energy Delivery Aging Workforce Costs per OUCC	$ 1,165,478
Annual Aging Workforce Costs per Company	1,719,580
Adjustment to O&M Expense	$ (554,102)

Notes:

(1) Amounts per workpapers for Exhibit No. MSH-3, Adjustment A23 except where noted.

(2) Labor loadings have been reduced to reflect exclusion of 0.5% FICA adder for incentive compensation.

(3) Amount per Company adjusted to exclude $25,000 of internal labor costs per response to OUCC-250a.

VECTREN SOUTH
Electric Tariff

Adjustment to Remove Non-Incremental Labor Costs
for Existing Employees
Test Year Ending March 31, 2006

		Amount
Labor Costs for Existing Employees Included in:		
Distribution Operations & Training--Adjustment A20 (1)	$	12,043
Boiler Systems Maintenance--Adjustment A32 (2)		108,077
Underground Facilities Maintenance--Adjustment A34 (3)		82,448
Reliability Planning--Adjustment A37 (4)		17,500
Total Non-Incremental Labor Costs to be Eliminated	$	220,068

Notes:

(1) Per response to OUCC-58.

(2) Per response to OUCC-258.

(3) Per response to OUCC-120.

(4) Amounts per workpapers for Exhibit No. MSH-3, Adjustment A37.

IURC Cause No. 43111
Schedule TSC-14

VECTREN SOUTH
Electric Tariff

Adjustment to Reflect Going Level MISO Day 2 Costs
Test Year Ending March 31, 2006

	Amount
MISO Day 2 Costs for 12 Months Ending December 31, 2006 (1)	$ 2,668,969
Pro Forma MISO Day 2 Costs per Company Filing (2)	5,420,266
Adjustment to MISO Day 2 Expense	$ (2,751,297)

Notes:

(1) Per Response to OUCC-296. Excludes Revenue Sufficiency Guarantee costs for period April through December 9, 2005.

(2) Company Exhibit MSH-3, Adjustment A13.

VECTREN SOUTH
Electric Tariff

Adjustment to the Amortization of Deferred MISO Day 2 Costs
Test Year Ending March 31, 2006

	Amount
Deferred MISO Day 2 Costs as of March 31, 2006 (1)	$ 5,218,293
Revenue Sufficiency Guarantee Costs for April through 12/09/2005 (2)	3,757,902
Actual MISO Day 2 Costs April-December 2006 (3)	2,345,755
Estimated Additional Costs for January-March 2007 (4)	667,242
Estimated MISO Day 2 Deferred Costs at March 31, 2007	$ 11,989,193
Proposed Amortization Period in Years	4
Annual Amortization	$ 2,997,298
Amortization Expense per Company	4,682,823
Adjustment to O&M Expense	$ (1,685,525)

Notes:
(1) Per Company Exhibit MSH-3, Adjustment A14.

(2) Per Response to OUCC-296.

(3) Per responses to OUCC-90 and OUCC-296. Excludes Revenue Sufficiency Guarantee Costs separately recognized.

(4) Based on average monthly costs in 2006 per Schedule TSC-14.

VECTREN SOUTH
Electric Tariff

Adjustment to the Amortization of Deferred MISO Day 1 Costs
Test Year Ending March 31, 2006

	Amount
Deferred MISO Day 1 Costs as of March 31, 2006 (1)	$ 4,663,899
Exclude FERC Assessment Fees (2)	(576,746)
Less: Misclassified Expense (2)	(10,000)
Deferred MISO Day 1 Administrative Costs at March 31, 2006	$ 4,077,153
Estimated Annual Expense for 9 Months Ended December 31, 2006 (3)	716,688
Estimated Deferred MISO Day 1 Costs at December 31, 2006	$ 4,793,841
Amortization Period in Years	4
Annual Amortization	$ 1,198,460
Amortization Expense per Company (2)	1,501,694
Adjustment to O&M Expense	$ (303,234)

Notes:
(1) Per Company Exhibit MSH-3, Adjustment A48.

(2) Per Response to OUCC-86.

(3) Based on 9 months of ongoing costs per Company Exhibit MSH-3, Adjustment A39.

VECTREN SOUTH
Electric Tariff

Adjustment to Environmental Chemical Costs
Test Year Ending March 31, 2006

	Amount
Normalized Chemicals Expense for 2007 (1)	$ 12,543,816
Pro Forma Expense per Company (2)	13,737,743
Total Pro Forma MISO Day 1 Costs per Company	$ (1,193,927)

Notes:
(1) Per Response to OUCC-298. Reflects normalized quantities and known contract prices for 2007. Excludes $80,232 of sulphur costs.

(2) Company Exhibit MSH-3, Adjustment A24. Excludes $80,232 of sulphur costs.

VECTREN SOUTH
Electric Tariff

Adjustment to Catalyst Expense
Test Year Ending March 31, 2006

	Amount
AB Brown Unit 2 Catalyst Replacement (1)	$ 1,200,000
Warrick 4 Catalyst Replacement (2)	552,500
Culley Unit 3 Fabric Filter (3)	111,000
Annual Expense	$ 1,863,500
Pro Forma Expense per Company (4)	2,540,000
Adjustment to Pro Forma Catalyst Expense	$ (676,500)

Notes:

(1) Per Response to OUCC-102. AB Brown Unit 2 scheduled for 2007. Culley Unit 3 was scheduled for 2006 and AB Brown Unit 1 is scheduled for 2008. Cost in all years is estimated at $1,200,000.

(2) Per response to OUCC 299. Estimated expense for 2007 is $552,500. Actual expense in 2006 was $323,000.

(3) Per responses to OUCC-102 and OUCC-299.

(4) Company Exhibit MSH-3, Adjustment A25.

IURC Cause No. 43111
Schedule TSC-19

VECTREN SOUTH
Electric Tariff

Adjustment to Substation Inspection Programs
Test Year Ending March 31, 2006

	Amount per Company (1)	Amount per OUCC (2)
Substation Inspection - Distribution Breakers	$145,286	$ -
Substation Inspection - Transmision Breakers	244,209	-
Infrared Inspection Program - Electric Substations	62,500	25,000
Substation Painting Program	450,000	300,000
Other Programs (3)	103,484	103,484
Total Proposed Program Costs	$1,005,479	$428,484
Adjustment to Substation Inspections Programs Expense		($576,995)

Notes:

(1) Per Workpaper for Company Exhibit MSH-3, Adjustment A33.

(2) Per testimony of OUCC witness Joan Soller.

(3) Includes SCADA maintenance, AEGIS Recommendations, removal of substation climbing aids and fire extinguisher maintenance.

VECTREN SOUTH
Electric Tariff

Adjustment to Line Clearance Expense
Test Year Ending March 31, 2006

	Amount
Normalized Line Clearance Expense (1)	$ 3,500,000
Test Year Expense (1)	1,867,000
Incremental Expense	$ 1,633,000
Additional Expense per Company (2)	1,860,232
Adjustment to Line Clearance Expense	$ (227,232)

Notes:
(1) Per Response to OUCC-121.

(2) Per Workpaper for Company Exhibit MSH-3, Adjustment A35.

IURC Cause No. 43111
Schedule TSC-21

VECTREN SOUTH
Electric Tariff

Adjustment to Overhead Facilities Maintenance Costs
Test Year Ending March 31, 2006

	Amount Per Company (1)	Amount Per OUCC (2)
Overhead Reliability Program	$ 1,492,800	$ 1,200,000
Pole Inspection Program	179,143	172,465
Infrared Inspection-Distribution	100,000	24,000
Infrared Inspection-Transmission	40,000	26,000
Overhead Inspection Program	24,000	-
Circuit Flyover Inspections	25,000	-
Pole Attachment	62,720	50,000
Transmission Tower Painting	250,000	62,500
Pole/Guy Grounding Program	301,428	83,200
Transmisson Tower Signage	13,100	13,100
Circuit Line Patrols	200,000	-
Line Specialist Apprentices per Company	472,542	141,763
	$ 3,160,733	$ 1,773,028
Adjustment to Overhead Facilities Maintenance Expense		(1,387,705)

Notes:
(1) Per workpapers for Exhibit No. MSH-3, Adjustment A36.

(2) Per testimony of OUCC witness Joan Soller.

IURC Cause No. 43111
Schedule TSC-22

VECTREN SOUTH
Electric Tariff

Adjustment to Normalize Uncollectibles Expense
Test Year Ending March 31, 2006

	Amount
Pro Forma Revenue at Present Rates(1)	$ 412,659,811
3-Year Average of Actual Write-offs (2)	0.26%
Uncollectibles Expense per OUCC	$ 1,072,916
Uncollectibles Expense per Company Filing (2)	1,568,107
Adjustment to Uncollectibles Expense	$ (495,191)

Notes:
(1) Per Schedule TSC-1

(2) Per Exhibit No. MSH-3, Adjustment A40 and related workpapers.

VECTREN SOUTH
Electric Tariff

Adjustment to Remove Incremental Meter Reading Expense
Test Year Ending March 31, 2006

	Amount
Incremental Meter Reading Expense per Company (1)	$ 39,467
Revenue Benefits for Meter Audit Program (2)	233,500
Adjustment to Eliminate Incremental Expense	$ (39,467)

Notes:
(1) Per workpapers for Exhibit No. MSH-3, Adjustment A41.

(2) Per response to OUCC-69.

VECTREN SOUTH
Electric Tariff

Adjustment to Advertising Expense
Test Year Ending March 31, 2006

	Amount
School Utility Safety Program (1)	$ 120,000
Total Additional Safety Advertising per Company (1)	400,000
Adjustment to Advertising Expense	$ (280,000)

Note:

(1) Per Exhibit No. MSH-3, Adjustment A45 and related workpapers.

VECTREN SOUTH
Electric Tariff

Adjustment to Annualize Property & Risk Insurance Expense
Test Year Ending March 31, 2006

	Amount (1)	Vectren South Electric
Common Risk Insurance Premiums		
Workers Compensation	$ 257,056	
Automobile Liability	218,448	
Excess Liability	1,661,963	
Directors & Officers Liability	1,136,369	
Blanket Crime	19,898	
Fiduciary Liability	149,838	
Miscellaneous Liability	1,917	
Total Common Risk Insurance Premiums	$ 3,445,489	
Allocation Factor for Vectren South (2)	44.00%	
Vectren South Common Risk Insurance Premiums	$ 1,516,015	
Allocation Factor for Vectren South - Electric (2)	76.00%	
Vectren South - Electric Common Risk Insurance		$ 1,152,172
Vectren South Risk Insurance Premiums		
Garagekeepers Liability	$ 1,898	
Allocation Factor for Vectren South - Electric (2)	76.00%	
Vectren South - Gas Risk Insurance		1,442
Vectren South Electric Risk Insurance		
Warrick 4 Fire Insurance		85,323
Property Insurance		
Above Ground Property	$ 1,298,339	
Allocation Factor for Vectren South - Electric (2)	86.70%	
Vectren South - Gas Above Ground Property Insurance		1,125,660
Total Property Insurance per OUCC		$ 2,364,597
Total Property Insurance per Company (2)		3,028,103
Adjustment to Property Insurance Expense		$ (663,506)

Notes:
(1) Per Response to OUCC-43

(2) Per Workpaper for Company Exhibit MSH-3, Adjustment A50.

VECTREN SOUTH
Electric Tariff

Adjustment to Normalize Injuries & Damages Expense
Test Year Ending March 31, 2006

	Amount (1)	
Claims Paid For The 12 Months ended March 31, 2006	$ 258,501	
Claims Paid For The 12 Months ended March 31, 2005	256,524	
Claims Paid For The 12 Months ended March 31, 2004	141,078	
3-Year Average Claims Paid		$ 218,701
Major Claim Paid January 2007 (2)	$ 400,000	
Amortization Expense over 5 Years		$ 80,000
Normalized Injuries and Damages Expense		$ 298,701
Injuries & Damages Expense per Company (1)		543,701
Adjustment to Injuries & Damage Expense		$ (245,000)

Notes:
(1) Per Workpaper for Company Exhibit MSH-3, Adjustment A51.

(2) Per response to OUCC-302.

VECTREN SOUTH
Electric Tariff

Adjustment to Outside Services Expense
Test Year Ending March 31, 2006

	Amount
Political Action Committee Fees (1)	$ 10,583
AAAC Acquisition & Kelley Walter-Non Utility Bankruptcy (1)	43,776
Outside Services to be Eliminated	$ 54,359

Note:

(1) Per responses to OUCC-53 and OUCC-244.

VECTREN SOUTH
Electric Tariff

Adjustment to Reflect Asset Charge at OUCC Rate of Return
Test Year Ending March 31, 2006

	Amount (1)
Utility Holdings Gross Plant	$ 235,090,990
Accumulated Depreciation	(94,214,554)
Utility Holdings Net Plant	$ 140,876,436
Grossed Up Cost of Capital (2)	9.65%
Asset Cost Return and Income Taxes	$ 13,594,576
Depreciation Expense	21,148,656
Total Property Taxes	1,069,000
Total Charges	$ 35,812,232
Blended Allocation Factor for Vectren South Electric	22.99%
Total Pro forma Asset Charge	$ 8,233,232
Total Pro forma Asset Charge per Company	8,973,132
Adjustment to Asset Charge	$ (739,900)

Notes:
(1) Per Company Exhibit No. MSH-3, Adjustment A57, except where noted.

(2) Reflects rate of return recommendation of OUCC Witness J. Randall Woolridge.

IURC Cause No. 43111
Schedule TSC-29

VECTREN SOUTH
Electric Tariff

Adjustment to Depreciation Expense
Test Year Ending March 31, 2006

	Plant Balance (1) (A)	Company Rate (1) (B)	OUCC Rate (2) (C)	Change in Depreciation Expense (3)
Brown Station				
SO2 Removal System	$ 63,230,770	4.05%	4.04%	$ (6,323)
Turbogenerator Units	90,258,252	2.78%	2.57%	(189,542)
Misc. Power Plant Equipment	6,900,369	2.70%	2.36%	(23,461)
Culley Station				
Boiler Plant Equipment	114,332,322	3.70%	3.36%	(388,730)
Multi-Pollutant Systems	49,000,000	6.28%	5.83%	(220,500)
Turbogenerator Units	55,580,680	4.78%	3.00%	(989,336)
Accessory Electric Equipment	5,966,722	0.67%	0.85%	10,740
Transmission Plant				
Underground Conductors & Devices	1,356,646	2.99%	2.63%	(4,884)
Distribution Plant				
Structures & Improvements	659,763	3.15%	3.14%	(66)
Poles, Towers & Equipment	46,720,775	3.51%	3.22%	(135,490)
Overhead Conductors & Devices	52,320,408	3.46%	2.43%	(538,900)
General Plant				
Electronic Equipment	740,854	11.83%	4.75%	(52,452)
Autos	242,933	22.40%	5.42%	(41,250)
Heavy Trucks	7,861,844	4.97%	1.11%	(303,467)
Change in Total Depreciation Expense				$ (2,883,663)
Less: Change in Transportation Equipment				$ (344,717)
Adjustment to Depreciation Expense				(2,538,945)

Notes:

(1) Per Company Exhibit No. MSH-3, Adjustment A58.

(2) Per testimony of of OUCC witness Michael Ileo.

(3) Equals Column (A) times (Column (C)-Column (B)).

VECTREN SOUTH
Electric Tariff

Adjustment to Indiana Utility Receipts Tax
Test Year Ending March 31, 2006

	Amount
Going Level Revenue at Present Rates (1)	$ 412,659,811
Less: Uncollectibles as Adjusted (2)	(1,072,916)
Less: Statutory Exemption (3)	(1,000)
Revenue Subject to Indiana Utility Receipts Tax	$ 411,585,895
IURT Tax Rate	1.40%
Pro Forma Indiana Utility Receipts Tax	$ 5,762,203
Pro Forma Indiana Utility Receipts Tax per Company (3)	5,755,270
Adjustment to Indiana Utility Receipts Tax	$ 6,933

Notes:
(1) Per Schedule TSC-1

(2) Per Schedule TSC-22.

(3) Per Exhibit No. MSH-3, Adjustment A56 and related workpapers.

VECTREN SOUTH
Electric Tariff

Comparison of Income Statement Adjustments
Test Year Ending March 31, 2006

Description	Amount Per Company	Amount Per OUCC	OUCC Adjustment
Operation Revenue Adjustments	$ (21,923,563)	$ (21,923,563)	$ -
Operating Expense Adjustments			
Fuel and Purchased Power			
Fuel Handling	332,391	-	(332,391)
Ongoing MISO Day 2 Costs	5,420,266	2,668,969	(2,751,297)
MISO Day 2 Deferral Amortization	4,682,823	2,997,298	(1,685,525)
All Other Fuel and Purchased Power	(168,942)	(168,942)	-
Total Fuel and Purchased Power Adjustments	$ 10,266,538	$ 5,497,325	$ (4,769,213)
Operation and Maintenance			
Annualize Labor-Existing Headcount	2,960,133	2,960,133	-
Restricted Stock and Stock Options	617,289	148,785	(468,504)
Incentive Compensation	311,785	(492,277)	(804,062)
Pension Expense	341,067	341,067	-
Postretirement Medical Expense	(294,807)	(294,807)	-
Training Expense	145,403	133,360	(12,043)
Incremental Headcount	1,671,876	182,679	(1,489,197)
Payroll Tax Adder	-	8,778	8,778
Aging Workforce-Power Supply	1,392,899	835,330	(557,569)
Aging Workforce-Energy Delivery	1,719,580	1,165,478	(554,102)
Environmental Chemicals	2,308,679	1,114,752	(1,193,927)
Catalyst Expense	2,540,000	1,863,500	(676,500)
Ash Disposal Costs	1,500,000	1,500,000	-
By Product Sales	984,850	984,850	-
Culley Unit I Expense Reduction	(794,573)	(794,573)	-
Turbine Maintenance	3,359,950	3,359,950	-
Flue Gas Desulphurization Structural Maint.	1,075,000	1,075,000	-
Wholesale Power Marrketing Trading Expense	(278,904)	(278,904)	-
Boiler Outage and Maintenance	1,078,855	970,778	(108,077)
Substation Inspection Programs	1,005,479	428,484	(576,995)
Underground Facilities Maintenance	354,280	271,832	(82,448)
Line Clearance	1,880,232	1,653,000	(227,232)
Overhead Facilities Maintenance	3,160,733	1,773,028	(1,387,705)
Reliability Studies and Planning	102,500	85,000	(17,500)
Ongoing Demand Side Management Programs	947,582	947,582	-
Ongoing MISO Day 1 Costs	1,342,877	1,342,877	-
Uncollectible Accounts Expense	(372,386)	(867,577)	(495,191)
Meter Reading Costs	39,467	-	(39,467)
Miscellaneous Billing Costs	20,715	20,715	-
Sales & Marketing Costs	95,090	95,090	-
Contact Center Costs	157,036	157,036	-
Safety Communications Costs	400,000	120,000	(280,000)
Information Technology Costs	180,346	180,346	-
New Source Review Amortization	985,111	985,111	-
MISO Day 1 Deferral Amortization	1,501,694	1,198,460	(303,234)
Rate Case Expense	377,333	377,333	-
Property and Risk Insurance	965,406	301,900	(663,506)
Injuries and Damages Claims	(678,893)	(678,893)	-
Other Cost Reductions	(99,680)	(344,680)	(245,000)
Changes in Cost Allocations	21,588	21,588	-
Asset Management Program Costs	103,480	103,480	-
Asset Management Program Savings	(35,923)	(35,923)	-
Outside Services	-	(54,359)	(54,359)
IURC Fee	73,681	73,681	-
VUHI Asset Charge	935,996	196,096	(739,900)
Total O&M Adjustments	$ 34,102,825	$ 23,135,084	$ (10,967,742)
Depreciation and Amortization			
Depreciation	161,266	(2,377,679)	(2,538,945)
Amortization of Deferred DSM Costs	5,545,114	5,545,114	-
Total Depreciation & Amortization Adjustments	5,706,380	3,167,435	(2,538,945)
Taxes			
Other	1,548,281	1,555,214	6,933
Income Taxes	(30,212,641)	(23,047,444)	7,165,197
Total Adjustments to Taxes	$ (28,664,360)	$ (21,492,231)	$ 7,172,129
Total Operating Expense Adjustments	$ 21,411,383	$ 10,307,613	$ (11,103,771)
Total Net Operating Income Adjustments	$ (43,334,946)	$ (32,231,176)	$ 11,103,771

VECTREN SOUTH
Electric Tariff

Determination of Revenue Increase/(Decrease)
Test Year Ending March 31, 2006

	Per Company	Per OUCC	Source
Rate Base	$ 1,017,759,887	$ 1,042,198,970	Schedule TSC-2
Required Rate of Return	8.08%	6.77%	
Net Operating Income Required	$ 82,234,999	$ 70,556,870	
Net Operating Income at Present Rates	29,549,978	40,557,926	Schedule TSC-1
Increase in Net Operating Income	$ 52,685,021	$ 29,998,945	
Revenue Multiplier	1.71604	1.71388	See Note (1)
Revenue Increase/(Decrease)	$ 90,409,801	$ 51,414,445	

Note:

(1) Calculation of Conversion Factor	Rate	Per Vectren South	Per OUCC
Revenues		1.00000	1.00000
Bad Debt		0.00380	0.00260
Base for Indiana Utility Receipts Tax			0.99740
Indiana Utility Receipts Tax	1.40%	0.01400	0.01396
IURC Fee	0.11%	0.00110	0.00110
Subtotal		0.98110	0.98234
Add back IURT		0.01400	0.01396
Net State Taxable Income		0.99510	0.99630
SIT Rate	8.50%	0.08500	0.08500
State Income Tax		0.08458	0.08469
Net Federal Taxable Income		0.89652	0.89765
FIT Rate	35.00%	0.35000	0.35000
Federal Income Tax		0.31378	0.31418
Revenue Conversion Factor		0.58274	0.58347
Revenue Multiplier		1.71604	1.71388